CALPINE NATURAL GAS TRUST ANNUAL REPORT 2003

CALPINE NATURAL GAS TRUST CLOSING UNIT PRICE

Calpine Natural Gas Trust (TSX-listed, CXT.UN) is a natural gas focused investment vehicle with a highly concentrated asset base in west-central Alberta. The business strategy of the Trust is to sustain and grow cash distributions per trust unit by focusing primarily on maintaining and increasing natural gas production on a cost effective basis through acquisitions and the development and exploitation of existing reserves.


Pouce Coupe
Grande Prairie
Sturgeon Lake
Mitsue
Calling Lake
Simonette
Whitecourt
Ashmont
Bigoray
Edmonton
Pembina
Joarcam
Wainwright
Daysland
Bellshill Lake
Sylvan Lake
Markerville
Provost
Innisfail
Ghost Pine
Drumheller
Calgary
Major
Others
BRITISH COLUMBIA
ALBERTA

. . . IT IS SAID, ARE OPTIMISTIC ABOUT THE FUTURE.

Calpine Natural Gas Trust ("CNG Trust") was created in the belief that North American demand for clean, efficient energy will continue to grow. And as CNG Trust supplies that demand, we will grow with it.

It's an optimistic view. What makes it achievable are experienced management, proven assets and a solid linkage to one of the largest natural gas consumers on the continent. These attributes forged an opportunity that was fielded to investors with the initial public offering of CNG Trust in September 2003. The oversubscribed IPO was completed on October 15, 2003.

It is therefore with pride that the Trust issues its first annual report to unitholders. In the short time it has existed:

- The IPO raised $203 million in total gross proceeds;
- The Trust began making regular monthly distributions to unitholders;
- Development drilling commenced at our core Markerville property; and
- Subsequent to year end, the Trust undertook a significant property acquisition.

These activities demonstrate that the Trust has already begun to fulfill its dual objectives of making regular monthly distributions and increasing unitholder value.

Calpine Corporation ("Calpine"), one of the largest natural gas fired power producers in North America, created the Trust to help secure natural gas to fuel its power business.

The origins of the Trust provide the impetus to achieve those objectives. Calpine holds 25% of the trust units and intends to purchase most (if not all) of CNG Trust's production at market price. This linkage with Calpine provides the Trust with strong sponsorship from a buyer of natural gas whose equity interests are fully aligned with those of other unitholders.

The Trust will continue making distributions while proceeding on an aggressive growth path with our two principal assets: people and properties.

CNG TRUST PEOPLE: EXPERIENCE AND DIVERSITY

The Trust begins operations with a very capable management team possessing a wealth of experience in the oil and gas industry. Prior to being named President and CEO, I held senior executive positions with Alberta Energy Company International, Nexen Inc. and Occidental Petroleum Corporation.

Mark Kuhn, our Vice President of Business Development, has over 22 years experience with Marathon Oil Company. Art MacNichol, our Vice President of Finance and Chief Financial Officer, has more than 18 years of experience in the Canadian oil and gas industry. His most recent position was Chief Financial Officer of the Calpine Power Income Fund. The experience our team brings to the Trust gives me complete confidence we can compete and excel in this competitive market.

Complementing CNG Trust's management team is the Board of Directors. Our Directors, the majority of whom are independent of management, represent an extraordinary reservoir of experience, particularly in the fields of energy and finance. Their advice, counsel and guidance has been and will be an enormous benefit to the Trust as we move forward.

NATURAL GAS PROPERTIES: STARTING WITH QUALITY

The Trust presents a great opportunity to set the framework to build a scalable business model, geared for growth and delivering value to unitholders. The starting point is our initial portfolio of properties acquired from Calpine. These properties are concentrated in central Alberta, historically one of the most productive regions of the Western Canadian Sedimentary Basin. They have the advantages of proximity to each other, year-round access, proven production profiles and long-life reserves.

As a testament to the quality of our initial reserve base, we saw only a 3% change in our production adjusted proved producing and proved plus probable reserves (compared to the old established reserves under National Policy 2-B) base at year end. Under the stricter new reporting guidelines of National

Instrument 51-101, our reserve base remained essentially intact because of the highly developed nature of our proved reserves, and the high quality of our probable reserves.

Another advantage is the diversified product stream. This is reflected in the Trust's financial results for the 78-day reporting period from October 15, 2003, to year end. Production revenue totaled $15.1 million before hedging revenue, of which 71% was generated from sales of natural gas, 16% from crude oil and 13% from natural gas liquids.

After adding gains from commodity hedging and deducting expenses, the Trust generated $9.9 million in cash flow. CNG Trust distributed $10.2 million or $0.375 per trust unit to investors. The total comprised 7.5 cents per unit for the initial "stub" period in October, plus 15.0 cents per unit for each of November and December. The Trust's distributions as a percentage of cash flow in 2003 were higher than our target of retaining between 10% and 20% of annual cash flow. The exercise of the over-allotment option by the underwriters increased the number of units to the public by 10%, resulting in a strong balance sheet but not the desired payout ratio.

However, the asset purchase from Calpine subsequent to year end utilized the Trust's strong balance sheet and brought the Trust's payout ratio back to its targeted payout range for the first quarter of 2004.

MOVING FORWARD: DEVELOPMENT AND ACQUISITIONS

The Trust intends to aggressively grow in two ways: by expanding production from current assets and through acquisitions that are accretive to cash flow and net asset value per trust unit.

In the first category, the Trust has begun a $10 million capital program of development drilling principally in our core areas of Markerville, Sylvan Lake and Innisfail. Initial production from the first wells began in the first quarter of 2004, and work will continue throughout the year. In addition, the Trust

has initiated an active program of attracting risk capital from conventional exploration and production companies through farm-out and partnering agreements.

The Trust has also begun growing by acquisition. In February we made a $40.5 million asset purchase of natural gas properties in the productive Peace River Arch region of northwestern Alberta.

This transaction demonstrates the long-term commitment of both Calpine and the Trust to growing a natural gas business in the Western Canadian Sedimentary Basin.

The Trust will continue to examine acquisition opportunities as they arise, both from Calpine and from other sources as well.

While commodity prices strongly influence cash flow, steady results will be driven by sustainable production volumes and mitigation of risk through price hedging.

We believe sustainable production volumes require both internal "organic" growth through the drill bit, combined with acquisitions.

Our objective is to reach at least a $1 billion enterprise value with a portfolio of quality internal growth opportunities over the next few years. This size constitutes a critical mass that will provide a platform for future expansion and increased efficiencies.

In closing, I would like to express my appreciation to the people who joined forces to create CNG Trust in a greatly compressed time frame. We welcome the challenge of generating value for unitholders in 2004 and beyond, and I look forward to reporting our progress as we move forward.

Gary S. Guidry
President and Chief Executive Officer

The Trust commenced trading on the Toronto Stock Exchange on October 15, 2003 with a foundation of high quality, long life natural gas assets in west-central Alberta. The Trust further built on this foundation with a significant property purchase from Calpine Corporation in February 2004.

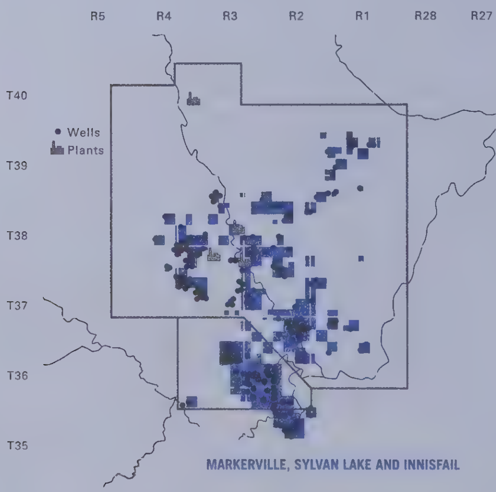
Gary S. Guidry
President and
Chief Executive Officer

Mark A. Kuhn
Vice President,
Business Development

Competition for natural gas properties is expected to be strong in 2004, due to an increasing number of competitors and a limited supply. The Trust's management and Board members were brought together with the experience and diversity to excel in this very competitive environment. We have a disciplined approach that builds on our foundation of quality properties and intend to generate excellent long-term value for our unitholders.

Art MacNichol
Vice President,
Finance and
Chief Financial Officer

The initial natural gas properties of CNG Trust are highly focused, with five core properties representing 80% of daily production and 87% of asset value. The Markerville, Sylvan Lake and Innisfail properties are located in west-central Alberta. Combined, these three properties represented 70% of the Trust's daily production in 2003 and 79% of the asset value at year end.



MARKERVILLE, SYLVAN LAKE AND INNISFAIL

MARKERVILLE, SYLVAN LAKE AND INNISFAIL

2003 Production(1)

Natural Gas	18,722 mcf/day
Crude Oil & NGL	685 bbls/day

Year End Reserves

Proved	11,495 Mboe
Proved Plus Probable	14,501 Mboe

Reserve Life Index

Proved	7.8 years
Proved Plus Probable	9.7 years

2004 Capital Program

Four infill horizontal well program at Markerville

Note:
(1) Working interest plus royalty interest production.

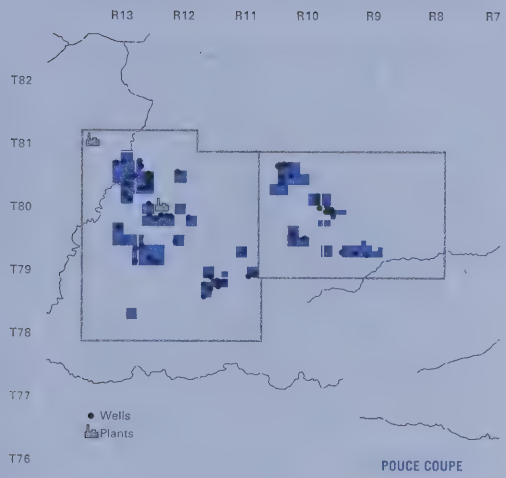
POUCE COUPE / GRANDE PRAIRIE

2004 Estimated Production [1]	
Natural Gas	6,607 mcf/day
Crude Oil & NGL	309 bbls/day
Year End Reserves	
Proved	2,569 Mboe
Proved Plus Probable	2,962 Mboe
Reserve Life Index	
Proved	5.0 years
Proved Plus Probable	5.8 years

Note:
(1) Production is based on independent evaluators' 2004 proved plus probable forecasted working interest plus royalty interest production.

MOVING FORWARD: ACQUISITIONS

On February 18, 2004 (effective January 1, 2004), CNG Trust acquired additional producing oil and natural gas properties from Calpine for total gross consideration of $40.5 million. This transaction added two new core areas located in the Peace River Arch of northwestern Alberta (Pouce Coupe and Grande Prairie). The natural gas focused acquisition increased proved and proved plus probable reserves by approximately 20% and 18%, respectively. This acquisition is forecasted to contribute approximately 25% of estimated 2004 production.


R13
R12
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T82
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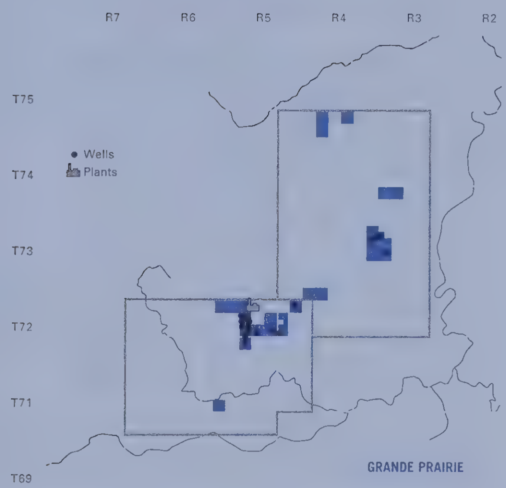
T77
T76
Wells
Plants
POUCE COUPE


R7
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T75
T74
T73
T72
T71
T69
Wells
Plants
GRANDE PRAIRIE

National Instrument 51-101 has significantly changed the reserve reporting landscape. CNG Trust is committed to providing its unitholders meaningful and informative financial and reserve information. Selected reserve information is disclosed below. Additional reserve information can be found in the Trust's Annual Information Form.

RESERVES

National Instrument ("NI") 51-101 was implemented on September 30, 2003 and took effect for companies reporting year end beginning December 31, 2003. NI 51-101 is replacing National Policy ("NP") 2-B. NI 51-101 expands the amount of information disclosed and attempts to bring more consistency, comparability and certainty to the reserves, assets and production data. NP 2-B did not utilize numeric probabilities of recovery, instead using phrases such as "less certain than proved" for probable reserves. This resulted in the industry practice of discounting probable reserves by 50%. Since under NI 51-101 risks are incorporated within specific evaluations, discounting probable reserves will not be necessary. The most important changes to reporting as a result of NI 51-101 are the reporting of reserves and reserve categories. The basic reserve classifications are:

1) Proved Reserves – this is a conservative estimate of remaining reserves. For reported reserves there must be at least a 90% probability that the quantities actually recovered will equal or exceed the estimated proved reserves.
2) Proved plus Probable – this is a reasonable estimate of remaining reserves. For reported reserves there must be at least a 50% probability that the quantities actually recovered will equal or exceed the sum of the proved plus probable reserves.

RESERVES GOVERNANCE

CNG Trust has a reserves committee with a majority of Independent Directors which:

- Reviews the qualifications and approves the selection of an independent reserves evaluation firm;
- Reviews the procedures for providing information to the independent evaluators;
- Reviews the reconciliation of changes in reserves and future net revenue;
- Reviews final evaluation with management and the independent evaluator, and after due diligence and clarification, recommends approval to the Board of Directors;
- Reviews procedures for reporting other information associated with oil and gas producing activities.

Based on an independent engineering evaluation conducted by Gilbert Laustsen Jung Associates Limited ("GLJ") effective December 31, 2003 and using GLJ's forecasted prices and costs as of January 1, 2004, CNG Trust had proved plus probable reserves of 81.3 bcf of natural gas and 5.6 Mbbls of crude oil and natural gas liquids. Approximately 71 percent of CNG Trust's reserves are natural gas and 29 percent crude oil and natural gas liquids. Total reserves at December 31, 2003 were 19.1 Mboe.

Compared to the previous GLJ report dated June 30, 2003 and filed in CNG Trust's Initial Public Offering prospectus, and after accounting for production, year end proved producing, total proved and proved plus probable reserves are within 3%, 9% and 3% respectively. Under the stricter new reporting guidelines of NI 51-101, the reserve base remained essentially intact because of the highly developed nature of the proved reserves (88% of the proved reserves are developed and producing), and the high quality of the probable reserves.

The following tables summarize CNG Trust's reserves as evaluated by GLJ and using GLJ's forecasted prices and costs as of January 1, 2004. These reserves reflect the Trust's working interest before royalties.

RESERVE SUMMARY

Reserves Category	Light and Medium Oil (Mbbls)	Natural Gas (Mmcf)	Natural Gas Liquids (Mbbls)	Oil Equivalent (Mboe)	Before Income Taxes, Discounted at (%/Year) 0	5	10
						(in $ thousands)	
Proved Reserves							
Proved Developed Producing	1,834	54,807	2,153	13,121	182,650	140,357	116,308
Proved Developed Non-Producing	5	2,435	37	448	8,376	5,270	3,832
Proved Undeveloped Reserves	35	6,333	245	1,336	18,644	11,877	8,046
Total Proved Reserves	1,874	63,575	2,435	14,904	209,670	157,504	128,186
Probable Reserves	604	17,681	642	4,193	70,279	40,548	27,708
Total Proved Plus Probable Reserves	2,478	81,256	3,077	19,097	279,949	198,052	155,895

RESERVE LIFE INDEX [1] ("RLI")

(years)	Light and Medium Oil	Natural Gas	Natural Gas Liquids	Oil Equivalent
Reserves Category				
Total Proved Reserves	6.7	7.8	7.9	7.7
Total Proved Plus Probable Reserves	8.5	9.8	9.9	9.6

Notes:

(1) Reserve life index is calculated using independent evaluator's forecast of first year production.

FORECAST PRICES AND COSTS (1) (2)

Year	Crude Oil: WTI Cushing Oklahoma ($US/bbl)	Crude Oil: Edmonton Par Price 40° API ($Cdn/bbl)	Natural Gas: AECO Gas Price ($Cdn/MMBTU)	Natural Gas Liquids: Edmonton Average ($Cdn/bbl) Propane	Butane	Pentane
2004	29.00	37.75	5.85	26.75	28.75	38.25
2005	26.00	33.75	5.15	21.75	23.75	34.25
2006	25.00	32.50	5.00	20.50	22.50	33.00
2007	25.00	32.50	5.00	20.50	22.50	33.00
2008	25.00	32.50	5.00	20.50	22.50	33.00
2009	25.00	32.50	5.00	20.50	22.50	33.00
2010	25.00	32.50	5.00	20.50	22.50	33.00
2011	25.00	32.50	5.00	20.50	22.50	33.00
2012	25.00	32.50	5.00	20.50	22.50	33.00
2013	25.00	32.50	5.00	20.50	22.50	33.00
2014	25.00	32.50	5.00	20.50	22.50	33.00
2015+ (3)	**+1.5%/yr**	**+1.5%/yr**	**+1.5%/yr**	**+1.5%/yr**	**+1.5%/yr**	**+1.5%/yr**

Notes:

(1) GLJ's January 1, 2004 forecasted prices and costs.

(2) Future prices incorporated a $0.75 US/Cdn exchange rate.

(3) Percentage change of 1.5% represents the change in future prices in each year after 2014 to the end of the reserve life.

RECONCILIATION OF RESERVES BY PRINCIPAL PRODUCT TYPE (1)
FORECAST PRICES AND COSTS

Factors	Light and Medium Crude Oil: Proved (Mbbls)	Probable (2) (Mbbls)	Proved Plus Probable (2) (Mbbls)	Associated and Non-Associated Gas: Proved (Mmcf)	Probable (2) (Mmcf)	Proved Plus Probable (2) (Mmcf)
June 30, 2003	1,956	501	2,457	76,787	13,954	90,741
Extensions	–	–	–	300	400	700
Improved Recovery	–	–	–	300	–	300
Technical Revisions	86	100	186	(9,322)	3,047	(6,275)
Discoveries	10	3	13	–	300	300
Acquisitions	–	–	–	–	–	–
Dispositions	–	–	–	(200)	(20)	(220)
Economic Factors	–	–	–	–	–	–
6 months of Production	(178)	–	(178)	(4,290)	–	(4,290)
December 31, 2003	1,874	604	2,478	63,575	17,681	81,256
Percent Revisions (3)	4.9%	20.6%	8.1%	–11.6%	26.7%	–5.7%

RECONCILIATION OF RESERVES BY PRINCIPAL PRODUCT TYPE (1)
FORECAST PRICES AND COSTS (continued)

	Natural Gas Liquids			Oil Equivalent (6:1)		
Factors	Proved	Probable (2)	Proved Plus Probable (2)	Proved	Probable (2)	Proved Plus Probable (2)
	(Mbbls)	(Mbbls)	(Mbbls)	(Mboe)	(Mboe)	(Mboe)
June 30, 2003	2,777	454	3,231	17,531	3,281	20,812
Extensions	13	15	28	63	82	145
Improved Recovery	14	1	15	64	1	65
Technical Revisions	(210)	174	(36)	(1,677)	838	(896)
Discoveries	–	–	–	10	53	63
Acquisitions	–	–	–	–	–	–
Dispositions	(4)	(1)	(5)	(37)	(4)	(41)
Economic Factors	–	–	–	–	–	–
6 months of Production	(157)	–	(157)	(1,050)	–	(1,050)
December 31, 2003	2,434	643	3,077	14,904	4,193	19,097
Percent Revisions (3)	–6.7%	41.6%	0.1%	–9.0%	27.8%	–3.2%

Notes:

(1) GLJ's January 1, 2004 forecasted prices and costs.

(2) June 30, 2003 Probable reserves are risked 50% to allow appropriate reconciliation with December 31, 2003 Probable reserves, which were evaluated under NI 51-101 requirements.

(3) Percent revisions include all revisions except 2003 production.

The largest change in proved reserves was a reduction due to technical revisions of approximately 1,500 Mboe in working interest gas reserves as a result of production performance and a more conservative approach under the NI 51-101 guidelines to proved undeveloped reserves in the Markerville field. Half of this reduction was offset by approximately 780 Mboe positive technical revisions in probable gas reserves, and in proved and probable oil reserves based on improved well performance. In addition, proved and probable undeveloped reserves will be developed by drilling four horizontal wells in the Markerville field. This development drilling program commenced in November and all the wells were completed in the first quarter of 2004. Production results from the four well program at Markerville will be considered in the 2004 reserves and also assist in identifying further development potential in this core field. Management expects the results of this drilling program to exceed GLJ's estimates.

ESTIMATED PRE-TAX NET CASH FLOWS – PROVED PLUS PROBABLE RESERVES (1)

($000's) Year	Annual Production (Mboe)	Partnership Interest Revenue (2)	Royalty Burdens	Operating Expenses (3)	Other Income (4)	Abandon-ment Costs (5)	Net Operating Income	Net Capital Investment	Net Cash Flow Before Income Tax (6)(7)
2004	1,998	67,332	14,822	12,628	836	0	40,717	4,671	36,047
2005	1,994	59,127	12,955	12,519	1,081	685	34,049	6,465	27,584
2006	1,725	49,779	10,707	11,637	987	760	27,662	314	27,348
2007	1,462	42,168	8,790	10,754	810	534	22,900	303	22,598
2008	1,269	36,584	7,429	9,811	667	521	19,489	486	19,004
2009	1,081	31,126	6,169	8,799	524	749	15,934	278	15,656
2010	931	26,761	5,240	7,547	439	1,560	12,853	272	12,581
2011	814	23,380	4,443	7,117	369	292	11,898	562	11,336
2012	732	20,990	3,950	6,247	314	657	10,450	346	10,103
2013	659	18,909	3,476	5,964	322	206	9,584	243	9,341
2014	633	18,163	3,421	5,834	290	248	8,951	275	8,675
2015	568	16,630	3,065	5,555	258	549	7,719	255	7,464
Subtotal	13,867	410,949	84,467	104,412	6,898	6,761	222,207	14,471	207,736
Remaining	5,386	187,479	29,481	79,731	2,215	6,105	74,379	2,166	72,213
Total	**19,253**	**598,428**	**113,948**	**184,142**	**9,113**	**12,866**	**296,586**	**16,636**	**279,949**

Total net cash flow before income taxes discounted (7) at:
5%: 198,052
10%: 155,895

Notes:
(1) GLJ's January 1, 2004 forecasted price and costs.
(2) Includes working interest revenue and royalty interest revenue.
(3) Includes mineral taxes and net profit interest payments.
(4) Includes processing revenues, overhead recoveries, and ARTC.
(5) Abandonment costs for current producing and future wells.
(6) Undiscounted
(7) Net cash flow before income taxes is stated prior to interest and general and administrative expenses.

ACQUISITION OF PEACE RIVER ARCH PROPERTIES

Subsequent to December 31, 2003, Calpine Natural Gas Trust closed the acquisition of natural gas properties (the "Property Purchase") from a wholly owned subsidiary of Calpine Corporation for gross consideration of $40.5 million. The effective date of the transaction is January 1, 2004 and the transaction closed February 18, 2004. The properties include a mix of operated and non-operated interests with the most significant interest in the Peace River Arch area of northwestern Alberta. The purchase provided two new gas weighted core areas for CNG Trust.

The acquisition, on a pro forma basis, increased proved and proved plus probable reserves by approximately 20% and 18%, respectively.

SELECTED PRO FORMA OPERATIONAL INFORMATION

The following table sets forth certain operational information for each of the Trust and the Property Purchase at December 31, 2003 and on a pro forma combined basis at December 31, 2003.

	CNG Trust	Property Purchase	Combined
Proved Reserves (1)			
Natural gas (Mmcf)	63,575	16,165	79,740
Crude oil and NGLs (Mbbls)	4,308	292	4,600
Total (Mboe)	14,904	2,986	17,890
Proved plus Probable Reserves (1)			
Natural gas (Mmcf)	81,256	18,717	99,973
Crude oil and NGLs (Mbbls)	5,555	362	5,917
Total (Mboe)	19,097	3,481	22,578
Net Present Value of Reserves ($ thousands) (1)			
(Forecast Prices and Costs, 10% discount rate)			
Proved Reserves	128,186	34,225	162,411
Proved plus Probable Reserves	155,895	38,346	194,241
2004 Average Forecasted Daily Production (2)			
Natural gas (mcf/day)	22,877	8,062	30,939
Crude oil and NGLs (bbls/day)	1,662	345	2,007
Total (boe/day)	5,475	1,689	7,164
Reserve Life Index (years) (3)			
Proved Reserves	7.7	5.1	7.4
Proved plus Probable Reserves	9.6	5.7	8.7

Notes:

(1) The reserve volumes and net present values for the Trust and the Property Purchase are based upon gross reserves (before deduction of royalties) and GLJ's forecasted price and costs.

(2) Production based on independent evaluator's total proved plus probable forecasted working interest and royalty interest production for 2004.

(3) Reserve life index is calculated by dividing the reserves by the independent evaluator's proved plus probable forecast of first year's working interest and royalty interest production.

ESTIMATED PRE-TAX NET CASH FLOWS – PROVED PLUS PROBABLE RESERVES OF PROPERTY PURCHASE [1]

($000's) Year	Annual Production (Mboe)	Partnership Interest Revenue [2]	Royalty Burdens	Operating Expenses [3]	Other Income [4]	Abandon-ment Costs [5]	Net Operating Income	Net Capital Investment	Net Cash Flow Before Income Tax [6][7]
2004	616	21,047	5,658	2,941	53	0	12,500	0	12,500
2005	477	14,225	3,621	2,434	43	119	8,094	0	8,094
2006	390	11,360	2,854	2,114	37	94	6,334	0	6,334
2007	307	8,934	2,226	1,737	32	262	4,741	0	4,741
2008	250	7,270	1,793	1,503	27	129	3,872	0	3,872
2009	209	6,070	1,467	1,331	24	116	3,180	0	3,180
2010	176	5,103	1,198	1,176	20	113	2,636	0	2,636
2011	152	4,405	1,005	1,068	18	80	2,271	25	2,246
2012	129	3,741	831	918	15	162	1,847	0	1,847
2013	111	3,223	697	806	14	29	1,704	0	1,704
2014	96	2,790	590	716	12	133	1,352	0	1,362
2015	85	2,519	519	672	11	12	1,327	0	1,327
Subtotal	2,997	90,687	22,459	17,416	305	1,247	49,868	25	49,843
Remaining	527	17,494	3,249	5,076	92	691	8,569	16	8,554
Total	3,524	108,181	25,708	22,492	397	1,938	58,438	41	58,397

Total net cash flow before income taxes discounted [7] at:
5%: 45,795
10%: 38,346

Notes:

(1) GLJ's January 1, 2004 forecasted price and costs.
(2) Includes working interest revenue and royalty interest revenue.
(3) Includes mineral taxes and net profit interest payments.
(4) Includes processing revenues, overhead recoveries.
(5) Abandonment costs for current producing and future wells.
(6) Undiscounted
(7) Net cash flow before income taxes is stated prior to interest and general and administrative expenses.


NATURAL GAS LIQUIDS
(NGL'S)

The following discussion and analysis as provided by management should be read in conjunction with the accompanying audited Consolidated Financial Statements of Calpine Natural Gas Trust ("CNG Trust" or the "Trust") and the accompanying notes for the period ended December 31, 2003 and is based on information available to March 19, 2004.

Management uses cash flow from operations (before changes in non-cash working capital ("cash flow")) to analyze operating performance and leverage. Cash flow presented does not have any standardized meaning prescribed by Canadian generally accepted accounting principles ("GAAP") and therefore it may not be comparable with the calculation of similar measures for other entities. Cash flow as presented is not intended to represent operating cash flow or operating profit for the period nor should it be viewed as an alternative to cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP. All references to cash flow throughout this MD&A are based on cash flow from operations before changes in non-cash working capital.

CNG Trust began operations on October 15, 2003 and therefore the following discussion and analysis describes the Trust's performance for the 78-day period from October 15, 2003 to December 31, 2003. Certain comparative information is provided, when informative, to assist the reader in analyzing CNG Trust's operating results.

2003 ACHIEVEMENTS

- Successfully completed the initial public offering ("IPO") of trust units on October 15, 2003 raising gross proceeds of approximately $184.5 million (approximately $203.0 million including underwriters over-allotment option).
- Hedging program implemented to manage exposure to fluctuations in commodity prices resulting in greater certainty and stability to distributions in 2004.
- CNG Trust distributed $10.2 million to unitholders ($0.375 per trust unit), and generated cash flow of $9.9 million ($0.37 per trust unit).
- CNG Trust commenced its four well development program at the core Markerville field investing $2.6 million in development drilling. Initial production from the first two wells of this drilling program commenced in February 2004.
- Subsequent to December 31, 2003 CNG Trust closed an acquisition of natural gas properties for $40.5 million with the most significant interest in the Peace River Arch area of northwestern Alberta (the "Property Purchase"). CNG Trust purchased the natural gas properties from an indirectly wholly owned subsidiary of Calpine Corporation.

CREATION OF CALPINE NATURAL GAS TRUST

On October 15, 2003, the Trust closed its IPO of 18,454,200 trust units at a price of $10.00 per trust unit. The Trust raised $173.1 million, net of costs associated with the offering. The net proceeds from the IPO, together with the proceeds of $61.5 million from the sale of the trust units to an indirectly wholly owned subsidiary of Calpine Corporation and approximately $40 million of bank debt, were used to acquire the Trust's initial natural gas and oil properties (the "Initial Properties"). As part of the IPO, the Trust granted the underwriters an option to purchase up to 1,845,420 trust units for a period expiring 30 days following the date of closing of the IPO. On October 22, 2003, the underwriters exercised this option in full for net proceeds of $17.4 million. Concurrently, a Canadian affiliate of Calpine Corporation maintained its 25% ownership in the Trust by fully exercising its option to acquire 615,140 trust units for additional net proceeds of $6.2 million. The net proceeds of $23.6 million were used to reduce bank debt. Following these transactions, the Trust had 27,066,160 trust units outstanding and listed on the Toronto Stock Exchange, of which 25% are owned by a Canadian affiliate of Calpine Corporation.

DESCRIPTION OF BUSINESS

Calpine Natural Gas Trust is an unincorporated open-ended investment trust created under the laws of Alberta. The Trust's unitholders are the sole beneficiaries of the Trust. The trust structure allows individual unitholders to participate in the cash flow of the business. Cash flow is realized from the Trust's ownership of natural gas and petroleum properties and related facilities. Calpine Natural Gas Limited, a wholly-owned subsidiary of the Trust, provides independent administrative and management services to the Trust and its subsidiaries. Pursuant to a Services Agreement, CNG Trust has engaged Calpine Natural Gas Services Limited ("Calpine Services"), an indirect wholly-owned subsidiary of Calpine Corporation, to assist the Trust's management by providing administrative and operating services to the Trust and its subsidiaries. In addition, an indirectly wholly-owned subsidiary of Calpine Corporation, Calpine Canada Natural Gas Partnership ("CCNGP"), arranges all marketing and transportation services for the Trust's natural gas and petroleum production pursuant to an Energy Management Services Agreement. Each of Calpine Services and CCNGP performs these services on an expense reimbursement basis.

The business strategy of the Trust is to sustain and grow cash distributions per trust unit by focusing primarily on maintaining and increasing natural gas production on a cost effective basis through acquisitions and the development and exploitation of existing reserves.

CRITICAL ACCOUNTING POLICIES

The financial statements have been prepared in accordance with Canadian GAAP. A summary of significant accounting policies are presented in Note 2 to the consolidated financial statements. Certain accounting policies are critical to understanding the financial condition and results of operations of CNG Trust. In accounting for oil and gas activities there are two choices available under Canadian GAAP; the full-cost and successful efforts methods of accounting.

The Trust follows the full-cost method of accounting for oil and natural gas activity, as described in Note 2 to the consolidated financial statements. Under the full-cost method of accounting, all costs of acquiring, exploring and developing petroleum and natural gas properties and asset retirement costs are capitalized, including unsuccessful drilling costs and administrative costs associated with acquisitions and development. Under the successful efforts

method of accounting, all exploration costs, except costs associated with drilling successful exploration wells, are expensed in the period in which they are incurred. The difference between these two methodologies is not expected to significantly effect the Trust's net earnings or net earnings per trust unit as the Trust participates in low risk development wells with historically high success rates.

In accounting for oil and natural gas activity under the full-cost method of accounting, the Canadian Institute of Chartered Accountants ("CICA") issued Accounting Guideline 16, "Oil and Gas Accounting – Full Cost" to replace CICA Accounting Guideline 5. The new guideline proposes amendments to the ceiling test calculation applied by the Trust. The Trust implemented this new guideline in 2003. The ceiling test is applied to the overall carrying value of the property, plant and equipment ("PP&E") for a Canada-wide cost centre. An impairment loss is recognized if the carrying value exceeds the sum of undiscounted cash flows expected to result from the use and eventual disposition of the Trust's proved reserves. Upon recognition of impairment the Trust would then measure the amount of impairment by comparing the carrying amounts of the PP&E to the fair value of the PP&E which will usually be equal to the estimated net present value of future cash flows from proved and probable reserves plus the costs of unproved properties that contain no probable reserves, and have been subject a separate test for impairment. Cash flows are based on third party quoted forward prices adjusted for the Trust's contract prices and quality differentials. The Trust's risk-free interest rate is used to calculate the Trust's net present value of the future cash flow. The Trust has one cost centre, as operations are currently conducted only in Canada. Under the successful efforts method of accounting, the costs are aggregated on a property by property basis. The carrying value of each property is subject to an impairment test by determining the fair value of the reserves based on estimates of future prices at period end. As each accounting methodology uses a different commodity price assumption and calculates impairment differently, each policy may generate a different net income and a different carrying value of PP&E, depending on the circumstances at period end.

In accounting for hedge activity, the CICA issued Accounting Guideline 13 "Hedging Relationships", effective for fiscal years beginning on or after July 1, 2003. The guideline deals with the identification, designation, documentation and measurement of effectiveness of hedging relationships for the purposes of applying hedge accounting.

The Trust has formally identified, designated, documented and measured all transactions that were determined to meet the criteria of effective hedges as at December 31, 2003. Had the Trust's contracts not qualified for hedge accounting, any changes in the mark-to-market values of the hedging contracts related to a period would have either reduced or increased net income and net income per trust unit for that period. The mark-to-market value of the financial contracts outstanding as at December 31, 2003 reflects an unrealized cost of $0.2 million.

OPERATING SUMMARY

In accordance with Canadian industry practice, production volumes, reserve volumes and revenues are reported on a gross basis, before deduction of Crown and other royalties, unless otherwise indicated. The Trust's results of operations are dependent on production volumes of natural gas, crude oil and natural gas liquids and the prices received for this production. Prices for these commodities have fluctuated widely during recent years and are determined by supply and demand factors, including weather and general economic conditions and changes in the Canadian/U.S. currency exchange rate.

Production

Production volumes for 2003 averaged 5,441 boe per day (converted at 6 mcf:1boe), consisting of 22,631 mcf per day of natural gas, 897 bbls per day of crude oil and 772 bbls per day of natural gas liquids. The Trust's 2003 production portfolio was weighted 69.3% to natural gas, 16.5% to crude oil and 14.2% to natural gas liquids.

Management anticipates that production will average approximately 6,600 to 7,200 boe per day in 2004 from existing properties and after taking into account the Property Purchase. This acquisition makes up approximately 25% of CNG Trust's estimated 2004 production and other than the Property Purchase, no further acquisitions are taken into account in estimating 2004 production.

Production from the Initial Properties, prior to being purchased by CNG Trust, was 7,191 boe per day in 2002, consisting of 30,348 mcf per day of natural gas, 1,068 bbls per day of crude oil and 1,065 bbls per day of natural gas liquids. Production from January 1 to September 30, 2003 was 5,979 boe per day, consisting of 24,204 mcf per day of natural gas, 1,042 bbls per day of crude oil and 903 bbls per day of natural gas liquids. Minimal capital expenditures were invested in the Initial Properties by Calpine Corporation in 2002 and 2003 due to a company-wide reduced capital expenditure program. Historically, production decline on the Initial Properties has averaged approximately 18% to 20% per year.

Principal Producing Properties

CNG Trust's properties are diversified from a geological and geographical perspective with three major areas (being Markerville, Sylvan Lake and Innisfail) comprising approximately 70% of the Trust's production on a boe basis. The following table summarizes the Trust's average production and reserves for the period ended December 31, 2003:

					Reserves	
Property	Natural Gas (mcf/day)	Crude Oil (bbls/day)	Natural Gas Liquids (bbls/day)	Total Production (boe/day)	Proved (Mboe)	Proved Plus Probable (Mboe)
Markerville	7,200	1	172	1,373	6,462	7,419
Sylvan Lake	9,440	98	342	2,013	4,012	5,882
Innisfail	2,082	–	72	419	1,021	1,200
Whitecourt	786	–	10	141	544	943
Provost	724	279	3	403	472	736
Bellshill Lake	35	222	3	230	706	953
Other	2,364	297	170	862	1,687	1,964
Total	22,631	897	772	5,441	14,904	19,097

Pricing and Price Risk Management

Call on Production Agreement

Concurrent with completion of the IPO on October 15, 2003, CNG Trust entered into a Call on Production Agreement with CCNGP, an indirectly wholly-owned subsidiary of Calpine Corporation. CCNGP has the right to purchase up to 100% of the production of natural gas and petroleum from the properties (including both the Initial Properties and subsequently acquired properties). The price that CCNGP pays for natural gas are the daily spot prices established by published indices (daily spot gas price at AECO), and the price that CCNGP pays for crude oil and natural gas liquids is its realized price negotiated with third party buyers. This agreement does not restrict the Trust's ability to enter into financial hedges, as described below. The Call on Production Agreement has a twenty year term, plus two automatic five year renewal terms, unless either party provides notice that it does not agree to renew the agreement. The Call on Production Agreement requires CCNGP to provide credit support in an amount sufficient to cover its payment obligations. Initially, the credit support consists of a pledge by Calpine Corporation of its trust units (market value at December 31, 2003 was $82.6 million) that it owns or controls along with the associated cash distributions.

Commodity Prices

The average price that CNG Trust received for its natural gas (before hedging) in 2003 was $6.07 per mcf. The Trust benefited from a hedge with CCNGP that was put in place concurrently with the completion of the IPO. The hedge provides the Trust with a minimum price of $7.35 per mcf on all the production from the Initial Properties (but not any properties acquired following completion of the IPO) from October 15, 2003 to April 15, 2004. This hedge resulted in a gain for the Trust of $2.3 million in 2003 or $1.28 per mcf.

The average price that CNG Trust received for its crude oil and natural gas liquids in 2003 was $34.32 per bbl and $33.35 per bbl respectively.

	2002 [1,2]	January 1 to September 30, 2003 [1,2]	October 15 to December 31, 2003
Benchmark prices			
AECO gas ($/mcf)	4.08	6.98	6.04
WTI crude oil (US$/bbl)	26.07	30.99	30.47
Average CNG Trust prices			
Natural gas before hedging ($/mcf)	4.03	6.95	6.07
Natural gas after hedging ($/mcf)	4.03	6.95	7.35
Crude oil ($/bbl)	35.11	40.93	34.32
Natural gas liquids ($/bbl)	27.28	36.84	33.35
Total oil equivalent before hedging ($/boe)	26.25	41.03	35.64

Notes:

(1) Prices received from the Initial Properties prior to being purchased by CNG Trust

(2) Prices provided by Calpine Corporation

Hedging

CNG Trust utilizes a hedging program to manage exposure to fluctuations in commodity prices, to provide greater certainty and stability to distributions, to protect unitholder return on investment and to help ensure profitability of specific properties or acquisitions. The Trust's hedging activities are conducted pursuant to the Trust's Risk Management Policy approved by the Board of Directors. The Risk Management Policy has the following objectives:

- To reduce risk exposure to budgeted annual cash flow projections resulting from uncertainty or changes in commodity prices, interest rates or foreign exchange to stabilize monthly distributions.
- To limit the permissible structures to ensure hedging effectiveness.
- To limit hedging up to a maximum of 50% of production for a maximum period of two years.
- To limit hedging activity to counter-parties that provide sufficient collateral in support of payment or have an investment grade credit rating.

The Trust is exposed to market risks resulting from fluctuations in commodity prices in the normal course of operations. The Trust uses various types of financial instruments to manage these market risks. Effective fiscal 2003, the Trust adopted the CICA's Accounting Guideline on hedging relationships as described above. Based on certain conditions established under the guideline, hedge accounting has been applied to options contracts held by the Trust at December 31, 2003. Had the Trust's contracts not qualified for hedge accounting, any changes in the mark-to-market values of the options contracts relating to a period would have either reduced or increased net income and net income per trust unit for that period.

Proceeds and costs realized from holding crude oil and natural gas contracts are recognized as a component of the related transaction.

At December 31, 2003, CNG Trust had the following financial hedges in place:

Commodity	Daily Notional Contract Quantity	Contract Price	Price Index	Term
Natural Gas Forward Sales Contract	100% of production from Initial Properties	min $7.35/mcf	AECO	October 15, 2003 to April 15, 2004
Natural Gas Fixed Price Contract	6,200 GJ	$5.20/GJ	AECO	April 1, 2004 to October 31, 2004
Natural Gas Collared Contract	6,200 GJ	min $4.75/GJ max $5.85/GJ	AECO	April 1, 2004 to October 31, 2004
Natural Gas Collared Contract	6,100 GJ	min $5.00/GJ max $6.80/GJ	AECO	November 1, 2004 to March 31, 2005

Subsequent to December 31, 2003, CNG Trust, in conjunction with the Property Purchase, entered into the following transactions:

Commodity	Daily Notional Contract Quantity	Contract Price	Price Index	Term
Natural Gas Fixed Price Contract	4,500 GJ	$5.90/GJ	AECO	April 1, 2004 to October 31, 2004
Natural Gas Collared Contract	2,000 GJ	min $5.25/GJ max $8.15/GJ	AECO AECO	November 1, 2004 to March 31, 2005

Cash Flow Sensitivities

The Trust's cash flow remains sensitive to changes in commodity prices, the Canada/US dollar exchange rate and interest rates as demonstrated by the following table:

Sensitivity to Changes in Commodity Price, Exchange Rate and Interest Rates	Estimated Effect on 2004 Cash Flow per Trust Unit
Change of $0.10 per mcf in the price of natural gas	$0.01
Change of US$1.00 per barrel in the price of WTI crude oil	$0.01
Change of 1,000 mcf/day in production	$0.05
Change of $0.01 in the US$/Cdn$ exchange rate	$0.01
Change of 1% in interest rate	$0.02

These sensitivities are based on management's current projections for 2004, which have been adjusted to include all commodity contracts as described above, inclusive of the Property Purchase. They apply to commodity prices, production, interest and exchange rates within the context of current market rates and the Trust's current risk management positions.

REVENUES AND ROYALTIES

Production revenues were $17.4 million for the period ended December 31, 2003, including $2.3 million of hedging revenue. Production revenues before hedging revenue consisted of $10.7 million from natural gas sales, $2.4 million from crude oil sales and $2.0 million from the sale of natural gas liquids. Natural gas, crude oil and natural gas liquids revenue made up 71%, 16% and 13% respectively of CNG Trust's total production revenue before hedging revenue. Hedging revenue reflected the price support received on the production from the Initial Properties as a result of the CCNGP hedge described above.

Royalties paid during the period ended December 31, 2003 were $3.7 million or 24.5% of production revenue before hedging revenue. In the current commodity price environment, CNG Trust expects royalty percentage to remain at approximately 24.5% in 2004.

OPERATING EXPENSES

Operating expenses for the period ended December 31, 2003 were $2.7 million or $6.29 per boe. During 2003 CNG Trust purchased six previously leased gas compressors in the Markerville and Sylvan Lake areas. This capital purchase will assist in reducing the Trust's operating costs, with estimated savings of approximately $70,000 per month. The full effect on reduced operating expenses from these compressor purchases will be realized in 2004 and beyond. Operating expenses per boe from the Initial Properties have increased over the last three years mainly due to reduced production rates per well and higher industry service costs. Operating costs per boe in 2002 and the period from January 1 to September 30, 2003 were $4.52 and $5.51 respectively. CNG Trust management anticipates that operating expenses in 2004 will be approximately $5.50 to $6.00 per boe, after taking into account the Property Purchase.

OPERATING NETBACKS

($/boe)	Year Ended December 31, 2002 (1)	January 1 to September 30, 2003 (1)	October 15 to December 31, 2003
	(unaudited)	(unaudited)	
Weighted average sale price	26.25	40.46	35.64
Hedging gain	–	–	5.32
Less royalties	6.12	10.37	8.72
Less operating expenses	4.52	5.51	6.29
Operating netbacks	15.61	24.58	25.95

Note:
(1) Information provided by Calpine Corporation.

GENERAL AND ADMINISTRATIVE EXPENSES

General and administrative ("G&A") expenses, net of overhead recoveries on operated properties, amounted to $976,000 ($2.30 per boe). In 2003 G&A expenses were high due to the costs associated with year end reporting requirements. Significant year end reporting expenses include the annual report, reserve report and external audit fees. In 2004, costs associated with year end reporting will be amortized over a full year which will significantly reduce 2004 G&A expenses per boe compared to 2003 G&A expenses per boe. Management expects general and administrative expenses to be approximately $1.30 to $1.50 per boe in 2004.

The Trust has entered into a Services Agreement with an indirect wholly-owned subsidiary of Calpine Corporation, Calpine Services. The Services Agreement has an initial ten year term which expires October 15, 2013 and will renew for one additional term of five years unless terminated by CNG Trust. Under the Services Agreement, Calpine Services provides certain administrative and operating services in order to assist management of the Trust in performing their duties and obligations. The overall supervision and direction of the Trust is provided by the independent executive officers of the Trust and the Trust's board of directors. Calpine Services provides these services to the Trust on an expense reimbursement basis. Total costs for these services, included in G&A expenses above, for the period ended December 31, 2003 was $380,000.

The Trust capitalized $84,000 of G&A in 2003. The majority of these capitalized costs represent compensation costs for staff involved in development and acquisition activities.

INTEREST EXPENSE

Interest expense for the period amounted to $192,000. Interest expense was minimized by financing debt through the issuance of lower cost bankers' acceptances as opposed to borrowing at the prevailing bank prime interest rates.

DEPLETION, DEPRECIATION AND AMORTIZATION

Depletion of PP&E is calculated using the unit-of-production method based on proved reserves determined in accordance with National Instrument 51-101 guidelines. Depletion, depreciation and amortization expense for 2003 was $8.9 million or $20.95 per boe. Assets to be depleted were increased by future development costs of $14.4 million and reduced by $2.8 million for the estimated future net realizable value of production equipment.

Depletion, depreciation and amortization expense for 2003 includes $7.8 million ($18.36 per boe) attributable to depletion of oil and gas costs, $126,000 ($0.30 per boe) attributable to depletion of asset retirement obligation asset and $970,000 ($2.29 per boe) attributable to amortization of the forward sales contract acquired pursuant to the IPO.

The Trust performed a ceiling test calculation at December 31, 2003 to assess the recoverable value of PP&E. The ceiling test limits were calculated based on year end proved reserves and the Trust's expected future pricing obtained from third parties and adjusted for commodity differentials specific to the Trust. Future prices were obtained for the period 2004 to 2008 inclusive and then escalated based on escalation factors in the Trust's year end independent reserves evaluation. Based on these assumptions, the carrying value of PP&E exceeded the sum of undiscounted cash flows expected by approximately $54.3 million.

The carrying value of PP&E was established through the IPO which was completed 78 days prior to year end. There was no significant change in the value of proved plus probable reserves from inception of the Trust to December 31, 2003 as calculated under National Instrument 51-101 and reviewed by an independent reserve engineer. Based on the value of the Trust's properties established by the IPO, the fair value of the Trust's PP&E exceeds its carrying value at December 31, 2003.

DISTRIBUTABLE CASH AND DISTRIBUTIONS

CNG Trust makes monthly cash distributions to its unitholders based upon the net cash flow from its natural gas and oil operations. A portion of this cash flow is typically withheld to repay bank debt and capital expenditures. During 2003, CNG Trust generated $9.9 million in cash flow ($0.37 per trust unit) from operations and $10.2 million ($0.375 per trust unit) was distributed to unitholders. The Trust's distributions as a percentage of cash flow (payout ratio) were higher than its annual target of distributing between 80% and 90%. The exercise of the over-allotment option by the underwriters increased the number of units to the public by 10%, resulting in a strong balance sheet but not the desired payout ratio. The Property Purchase, subsequent to year end, from Calpine Corporation, utilized the Trust's strong balance sheet. Management expects this purchase to return CNG Trust's payout ratio for the first quarter of 2004 back to its targeted payout range.

Management monitors the Trust's distribution payout policy with respect to forecasted cash flow, debt levels and capital expenditures. The Trust expects to retain between 10% and 20% of annual cash flow in 2004 for debt repayment and capital expenditures. The key drivers of CNG Trust's cash flow, as is the case with all other oil and gas trusts, are commodity prices and production. Since CNG Trust's production is heavily weighted to natural gas (69.3% in 2003), natural gas prices have a significant effect on its cash flow.

TAX TREATMENT OF DISTRIBUTIONS

CNG Trust has provided to unitholders general comments regarding the taxability of distributions but does not intend to provide legal or tax advice. Unitholders or potential investors should seek their own legal or tax advice in this regard.

Canadian Individual Unitholders

The Trust qualifies as a mutual fund trust under the Income Tax Act (Canada) and, accordingly, trust units of the Trust are qualified investments for RRSPs, RRIFs, RESPs and DPSPs. Each year, the Trust is required to file an income tax return and any taxable income in the Trust is allocated to the unitholders. Unitholders are generally required to include in computing income their pro-rate share of any taxable income earned by the Trust in that year. An investor's adjusted cost base ("ACB") in a trust unit equals the purchase price of the trust units less any non-taxable cash distributions received from the date of acquisition. To the extent a unitholder's ACB is reduced below zero, such amount will be deemed to be a capital gain to the unitholder and the unitholder's ACB will be brought to $nil.

CNG Trust paid $0.375 per trust unit in respect of 2003. For Canadian tax purposes, approximately 60% of these distributions, or $0.225 per trust unit was a tax deferred return of capital, approximately 40% or $0.15 per trust unit was taxable to unitholders as other income.

United States Resident Unitholders

U.S. resident unitholders who receive cash distributions are generally subject to a 15% Canadian withholding tax, applied to the taxable portion of the distribution as computed under Canadian tax law. U.S. taxpayers may be eligible for a foreign tax credit with respect to Canadian withholding taxes paid. The foreign tax credit limitations are very complex and U.S. taxpayers should consult with their tax advisors regarding its application.

CNG Trust elected to be treated as a partnership for U.S. tax purposes for the 2003 tax year. U.S. unitholders are taxable on their share of partnership income calculated applying U.S. tax principles regardless of actual distributions during the year. Distributions less than the U.S. unitholder's share of partnership income results in a net increase of the U.S. unitholder's tax basis in the trust units. Distributions during the year more than the U.S. unitholder's share of partnership income results in a net decrease of the U.S. unitholder's tax basis in the trust units. A net decrease in excess of the U.S. unitholder's basis should be reported as a gain.

The following table summarizes tax information for United States resident unitholders:

Record Date	Payment Date	Total Distributions (US$)	Allocation of Partnership Income (US$)	Net Decrease in Unitholder's Basis (US$)
November 30, 2003	December 15, 2003	$0.171	$0.121	$0.05

U.S unitholders should note that the December 2003 distribution paid on January 15, 2004 was not included in their 2003 tax return, but will be included in their 2004 tax return.

CAPITAL EXPENDITURES

During 2003, CNG Trust incurred $7.3 million on capital expenditures consisting of $3.3 million for drilling and completions and $4.0 million for facilities. Drilling and completion expenditures mainly consist of two horizontal development wells in the core Markerville field. Drilling programs for both wells were not completed until January 2004. Facilities capital expenditures were mainly comprised of the purchase of six previously leased gas compressors in the Markerville and Sylvan Lake areas.

The capital expenditures on the Initial Properties in 2002 were $2.0 million and for the period from January 1, 2003 to September 30, 2003 capital expenditures were $3.8 million reflecting Calpine Corporation's reduced capital expenditure program.

The 2004 capital budget on current properties and after taking into account the Property Purchase is $10.0 million. Approximately $7.0 million will be directed at drilling and completions, $1.4 million for facilities and maintenance and $1.6 million for land, seismic and geological and geophysical expenditures. The majority of 2004 capital will be directed to complete and tie-in two Markerville wells that commenced drilling in 2003 and drill, complete and tie-in two additional Markerville wells. These wells were drilled in the first quarter of 2004.

ABANDONMENTS

CNG Trust's objective is to take a proactive approach to environmental issues and abandonment and reclamation of associated well and facility sites as required. CNG Trust will annually carry out a program to abandon and reclaim wells and facilities which have reached the end of their economic lives. The Trust has established a reclamation fund into which $120,000 cash plus interest earned was contributed during the period ended December 31, 2003. Future contributions are currently set at approximately $0.28 per boe in order to provide for the future abandonment and site reclamation costs as recognized and presented in Note 8 to the consolidated financial statements.

LIQUIDITY AND CAPITAL RESOURCES

Bank debt at December 31, 2003 was $21.5 million with total available credit lines of $71.0 million. Subsequent to December 31, 2003, in conjunction with the Property Purchase from Calpine Corporation, the Trust's lenders increased the Trust's two credit facilities under which it could borrow up to $82.0 million. The syndicated revolving credit facility was increased from a borrowing limit of $66.0 million to $72.0 million and the Working Capital Facility increased from $5.0 million to $10.0 million. Net debt to total capitalization at December 31, 2003 was 8.6% and debt to cash flow payout was approximately 0.5 years based upon annualized cash flow from operations of $46.5 million and net debt of $21.5 million.

CNG Trust plans to finance future commitments with a combination of cash flow from operations, debt and equity. Cash flow used to finance these commitments will reduce the amount of cash distributions paid to unitholders.

OUTLOOK

The level of cash flow for 2004 will be affected by natural gas and crude oil prices, the Canadian/US dollar currency exchange rate and the Trust's ability to add reserves and production in a cost effective manner. Both product prices and exchange rates have showed significant volatility in 2003 and this trend is expected to continue in 2004.

Competition for natural gas properties is expected to be strong in 2004, due to an increasing number of competitors and a limited supply. The Trust expects to be an active participant but with a continued disciplined value approach.

It is CNG Trust's business strategy to sustain and grow distributions per trust unit providing unitholders with strong returns. The key objectives of the business strategy include:

- Accretive strategic acquisitions.
- Increase trust unit value through active management of CNG Trust's assets.
- Continuous program of attracting risk investment capital to create unitholder value.
- Controlling operating, G&A and finding and development costs.
- Actively hedging a portion of the Trust's production to enhance long-term returns and stabilize distributions.
- Proactive environmental and safety programs.
- Building strong relationships with partners and unitholders.

RISK FACTORS AND RISK MANAGEMENT

Investors that purchase trust units of CNG Trust are participating in the net cash flow from a portfolio of natural gas and crude oil producing properties. As such, the cash flow paid to investors and the value of CNG Trust's units is subject to numerous risk factors. The following information is only a summary of certain risk factors, many of which are associated with the oil and gas industry, which could affect the Trust's future results:

Volatility of Commodity Prices

The Trust's results of operations and financial condition are dependent on prices received for the production of natural gas and crude oil. Prices for natural gas and crude oil have fluctuated widely during recent years and are determined by supply and demand factors, including weather and general economic conditions as well as conditions in other oil producing regions, which are beyond the control of the Trust. Prices received from production in Canada also reflect changes in the Canadian/U.S. currency exchange rate. Any decline in the prices for natural gas and crude oil could have a material adverse effect on the Trust's operations, financial condition and the level of capital expenditures provided for the development of its natural gas and crude oil reserves.

CNG Trust uses financial derivative instruments in an effort to limit a portion of the potential adverse effects resulting from volatility in natural gas and oil commodity prices, while retaining exposure to upside price movements. The Trust's hedging activities are conducted pursuant to the Trust's Risk Management Policy approved by the Board of Directors. To the extent commodity price exposure is hedged, the benefits that would otherwise be experienced if commodity prices were to increase would be forgone.

Operational Matters

The ownership and operation of oil and natural gas wells, pipelines and facilities involves a number of operating and natural hazards which may result in blowouts, environmental damage and other unexpected or dangerous conditions resulting in damage to the Trust's natural gas and oil properties and assets as well as possible liability to third parties. The Trust may become liable for damages arising from such events against which it cannot insure or against which it may elect not to insure because of high premium costs or other reasons. Costs incurred to repair such damage or pay such liabilities will reduce the cash flow of CNG Trust.

CNG Trust employs prudent risk management practices and maintains suitable liability insurance, where available. Business interruption insurance is also purchased for selected facilities, to the extent that such insurance is reasonably available.

Reserves Risk

The value of CNG Trust's units is based on the underlying value of the natural gas and oil reserves. Natural gas and oil reserves decrease as they are produced over time. CNG Trust's ability to replace production depends on its success in acquiring new reserves and developing existing reserves. Acquisition of oil and natural gas assets depends on the Trust's assessment of value at the time of acquisition. Incorrect assessments of value can adversely affect distributions to unitholders and the value of the trust units.

The price that the Trust pays to acquire natural gas and oil properties is partially based on engineering and economic assessments made by independent petroleum engineers as well as actual historical financial and operating results. These assessments and historical results include a number of material assumptions and factors regarding matters such as recoverability and marketability of natural gas, natural gas liquids and crude oil, future prices of natural gas, natural gas liquids and crude oil, operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond the control of the operators. In particular, changes in the prices of and markets for petroleum, natural gas and natural gas liquids from those anticipated at the time of making such assessments will affect the return on value of the trust units. In addition, all such assessments involve a measure of geological and engineering uncertainty which could result in lower production and reserves than that attributed to the properties.

Acquisitions are subject to due diligence, review and investment parameters. Acquisitions exceeding $5 million require approval by the Trust's Board of Directors. Independent reservoir engineers evaluation, legal, tax and technical advice is received on all material acquisitions.

Access to Capital Markets

The Trust distributes the majority of is cash flow to unitholders. Access to equity and debt capital markets is required for the Trust to finance acquisition and development activity to maintain and grow value to unitholders.

CNG Trust's trust units are listed on the Toronto Stock Exchange and CNG Trust maintains an active investor relations program designed to facilitate access to equity capital markets.

CNG Trust maintains a prudent capital structure by retaining a portion of its net cash flow for debt repayment when appropriate, managing capital expenditures within rate of return and risk parameters and by utilizing equity markets.

Regulatory Risk

There can be no assurance that government royalties, income tax laws, environmental laws and regulatory requirements relating to the oil and gas industry, such as the status of mutual fund trusts, will not be changed in a manner which adversely affects the Trust or its unitholders.

Although the Trust has no control over these regulatory risks, CNG Trust continuously monitors changes in these areas to assess the impact of such changes on the Trust's financial and operating results.

Environmental and Safety Risks

The oil and natural gas industry is subject to environmental and safety regulation pursuant to local, provincial and federal legislation. A breach of such legislation may result in the imposition of fines or issuance of clean up orders in respect of the Trust or its properties. Such legislation may be changed to impose higher standards and potentially more costly obligations on the Trust.

CNG Trust has a site inspection program designed to ensure compliance with environmental laws and regulations.

CNG Trust has training and safety programs designed to educate personnel on safety awareness, monitor incidents and prevent accidents.

CNG Trust has established a reclamation fund for the purpose of funding its currently estimated future environmental and reclamation obligations based on its current knowledge.

Credit Risks

CNG Trust assumes customer credit risk associated with oil and gas sales, financial hedging transactions and joint venture participants. Under a Call on Production Agreement with CCNGP, an indirectly wholly-owned subsidiary of Calpine Corporation, has the right to purchase up to 100% of the Trust's production of natural gas and petroleum. There is no guarantee that Calpine Corporation will make the required payments under the Call in Production Agreement for production purchased from the Trust.

Management has established controls designed to mitigate the risk of default or nonpayment with respect to oil and gas sales, financial hedging transactions and joint venture participants. In the case of the Call on Production Agreement, CCNGP is required to provide credit support in an amount sufficient to cover its payment obligation (the Trust believes the maximum potential revenue shortfall to equal approximately two months of production revenue).

FORWARD LOOKING STATEMENTS

This discussion and analysis contains forward-looking statements relating to future events of future performance. In some cases, forward-looking statements can be identified by terminology such as "anticipates", "may", "will", "should", expects", "projects", "plans", "forecasts" and similar expressions. These statements represent management's expectations or beliefs concerning among other things, future operating results and various components thereof or the economic performance of CNG Trust. Undue reliance should not be placed on these forward-looking statements which are based upon management's assumptions and are subject to known and unknown risks and uncertainties, including the business risks discussed above, which may cause actual performance and financial results in future periods to differ materially from any projections of future performance or results expressed or implied by such forward-looking statements. Accordingly, readers are cautioned that events or circumstance could cause results to differ materially from those predicted. CNG Trust undertakes no obligation to update publicly or review any forward-looking statements contained herein and such statements are expressly qualified by the cautionary statement.

GLOSSARY OF ABBREVIATIONS

AECO	Alberta Energy Company interconnect with the Nova System
bbls	barrels
bbls/day	barrels per day
bcf	billion cubic feet
boe*	barrels of oil equivalent
boe/day*	barrels of oil equivalent per day
Mbbls	thousand barrels
Mboe*	thousand barrels of oil equivalent
mcf	thousand cubic feet
mcf/day	thousand cubic feet per day
MMBTU	million British Thermal Units
Mmcf	million cubic feet
RLI	reserve life index
TSX	Toronto Stock Exchange
WTI	West Texas Intermediate at Cushing, Oklahoma

* 6 mcf of gas = 1 barrel of oil

REPORT OF MANAGEMENT

The consolidated financial statements are the responsibility of the Management of Calpine Natural Gas Trust and have been approved by the Trust's Board of Directors. The accompanying consolidated financial statements have been prepared by Management in accordance with Canadian generally accepted accounting principles ("GAAP") and include amounts that are based on estimates and judgments. Financial information contained elsewhere in this Report is consistent with the consolidated financial statements.

Management has prepared Management's Discussion and Analysis, which is based on Calpine Natural Gas Trust's financial information prepared in accordance with GAAP and should be read in conjunction with the consolidated financial statements and accompanying notes.

Management has developed and maintains a system of internal controls and believes that these controls provide reasonable assurance that financial records are reliable and form a proper basis for preparation of financial statements.

The Board of Directors of Calpine Natural Gas Trust has appointed an Audit Committee, which meets periodically during the year with Management, and the external auditors independently and as a group. The Audit Committee reviews the consolidated financial statements with Management and the external auditors before the consolidated financial statements are submitted to the Board of Directors for approval. The external auditors have free access to the Audit Committee without obtaining approval from Management.

The independent external auditors, PricewaterhouseCoopers LLP, have been appointed by the Board of Directors to express an opinion as to whether the consolidated financial statements present fairly, in all material respects, Calpine Natural Gas Trust's financial position, results of operations and cash flows in accordance with GAAP. The following report of PricewaterhouseCoopers LLP outlines the scope of their examination and their opinion on the consolidated financial statements.

Gary Guidry
President and Chief Executive Officer
Calpine Natural Gas Limited

Art MacNichol
Vice President, Finance and Chief Financial Officer
Calpine Natural Gas Limited

February 6, 2004

AUDITORS' REPORT

To the Unitholders of Calpine Natural Gas Trust:

We have audited the consolidated balance sheet of Calpine Natural Gas Trust as a December 31, 2003 and the consolidated statement of earnings and unitholders' equity and cash flows for the period from October 15, 2003 to December 31, 2003. These consolidated financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2003 and the results of its operations and its cash flows for the period from October 15, 2003 to December 31, 2003 in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Calgary, Alberta
February 6, 2004
(except for note 14 which is dated February 25, 2004)

PricewaterhouseCoopers LLP.
Chartered Accountants

CONSOLIDATED BALANCE SHEET

(thousands) (audited)		As at December 31, 2003
ASSETS		
Current Assets		
Cash and cash equivalents	$	3,002
Accounts receivable (Note 9)		7,649
Prepaid expense and other		1,596
Forward sales contract (Note 4)		1,318
		13,565
Reclamation fund (Note 5)		120
Property, plant and equipment (Note 6)		275,150
	$	288,835
LIABILITIES		
Current Liabilities		
Accounts payable and accrued liabilities	$	9,654
Distributions payable		4,060
Bank debt (Note 7)		21,471
		35,185
Asset retirement obligation (Note 8)		4,654
UNITHOLDERS' EQUITY		
Unitholders' capital (Note 10)		258,189
Accumulated earnings		957
Accumulated distributions (Note 11)		(10,150)
		248,996
	$	288,835

See accompanying notes to the consolidated financial statements

Approved on behalf of the Board

W. Mark Schweitzer
Director

Robert B. Michaleski
Director

CONSOLIDATED STATEMENT OF EARNINGS AND UNITHOLDERS' EQUITY

(thousands, except for trust units and per trust unit amounts) (audited)	October 15, 2003 to December 31, 2003
REVENUES	
Production revenue	$ 17,385
Royalties	(3,702)
	13,683
EXPENSES	
Operating	2,668
General and administrative (Note 12)	976
Interest and financing (Note 7)	192
Depletion, depreciation and amortization (Notes 4 & 6)	8,890
	12,726
NET EARNINGS	957
UNITHOLDERS' EQUITY, BEGINNING OF PERIOD	–
Units issued, net of transaction fees (Note 10)	258,189
Distributions	(10,150)
UNITHOLDERS' EQUITY, END OF PERIOD	$ 248,996
Basic and fully diluted trust units outstanding	27,066,160
Net earnings per trust unit	$ 0.04

Distributable Cash and Distributable Cash per trust unit – See Note 11

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENT OF CASH FLOWS

(thousands) (audited)	October 15, 2003 to December 31, 2003
OPERATING ACTIVITIES	
Net earnings	$ 957
Add items not involving cash:	
Accretion expense (Note 8)	83
Depletion, depreciation and amortization	8,890
Cash flow from operations	9,930
Increase in non-cash working capital	(2,952)
	6,978
FINANCING ACTIVITIES	
Issue of trust units, net (Note 10)	258,189
Bank debt, net (Note 7)	21,471
Cash distributions paid	(6,090)
	273,570
INVESTING ACTIVITIES	
Acquisition of oil and gas properties (Note 3)	(273,489)
Capital expenditures	(7,298)
Reclamation fund contributions (Note 5)	(120)
Decrease in non-cash working capital	3,361
	(277,546)
INCREASE IN CASH AND CASH EQUIVALENTS	3,002
Cash and Cash Equivalents, beginning of period	–
Cash and Cash Equivalents, end of period	$ 3,002

See accompanying notes to the consolidated financial statements

1. FORMATION OF THE TRUST

Calpine Natural Gas Trust (the "Trust") is an unincorporated open-ended investment trust created under the laws of Alberta pursuant to a Trust Indenture dated August 22, 2003 between Calpine Natural Gas Limited ("Managing Partner") and Computershare Trust Company of Canada. The Trust's unitholders are the sole beneficiaries of the Trust.

The Trust was created for the purposes of issuing trust units to the public and investing the funds raised in petroleum and natural gas properties. The operations of the Trust consist of the acquisition, development, exploitation and disposition of these assets and the distribution of net cash proceeds from these activities to the unitholders.

2. SUMMARY OF ACCOUNTING POLICIES

The consolidated financial statements of the Trust have been prepared by management in accordance with Canadian generally accepted accounting principles ("GAAP"). The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingencies at the date of the financial statement, and revenues and expenses during the reporting period. Actual results could differ from those estimated.

In particular, the amounts recorded for depletion and depreciation of petroleum and natural gas properties and for asset retirement obligations are based on estimates of reserves and future costs. By their nature, these estimates and those related to future cash flows used to assess impairment, are subject to measurement uncertainty and the impact on the financial statements of future periods could be material.

(a) Basis of Consolidation

The consolidated financial statements include the accounts of the Trust and its subsidiaries: the Managing Partner, Calpine Natural Gas Commercial Trust ("Commercial Trust"), Calpine Natural Gas Holdings Limited ("Holdings") and Calpine Natural Gas, L.P. ("Partnership"). All inter-entity transactions have been eliminated.

(b) Cash and Cash Equivalents

Cash includes short-term and demand deposits with a term to maturity of three months or less when purchased and are recorded at cost, which approximates market value.

(c) Property, Plant and Equipment ("PP&E")

The Trust follows the full-cost method of accounting whereby all costs of exploring, developing and acquiring petroleum and natural gas properties including asset retirement costs, are capitalized and accumulated in one cost centre as all operations are in Canada. Maintenance and repairs are charged against earnings, and renewals and enhancements which extend the economic life of the PP&E are capitalized. Gains and losses are not recognized on disposition of oil and natural gas properties unless such a disposition would alter the rate of depletion by 20 percent or more.

In September 2003, the Canadian Institute of Chartered Accountants ("CICA") issued Accounting Guideline 16 which proposes amendments to the ceiling test calculation applied by the Trust under the full-cost method. Effective fiscal 2003, the Trust adopted this guideline. The Trust places a limit on the aggregate carrying value of PP&E, which may be amortized against revenues of future periods ("ceiling test"). An impairment loss is recognized if the carrying value exceeds the sum of undiscounted cash flows expected to result from the use and eventual disposition of the Trust's proved reserves. Cash flows are based on third party quoted forward prices, adjusted for the Trust's contract prices and quality differentials. The cost of unproved properties that contain no probable reserves, which have been subject to a separate test for impairment are included in the cost centre impairment test for recoverability.

Upon recognition of impairment, the Trust would then measure the amount of impairment by comparing the carrying amounts of the PP&E to the fair value of the PP&E which will usually be equal to the estimated net present value of future net cash flows from proved plus probable reserves. The Trust's risk-free interest rate is used to calculate the Trust's net present value of the future cash flows.

(d) Depletion and Depreciation

Depletion of petroleum and natural gas properties and depreciation of production equipment are calculated using the unit-of-production method based on the Trust's share of estimated proved reserves of oil and natural gas properties, calculated in accordance with National Instrument 51-101, as determined by management and reviewed by an independent reserve engineer, and total capitalized costs plus estimated future development costs of proved undeveloped reserves less estimated net realizable value of production equipment and facilities after proved reserves are fully produced. Natural gas reserves and production are converted, before royalties, to an equivalent volume of oil on an energy equivalent basis of six thousand cubic feet of natural gas to one barrel of oil.

(e) Asset Retirement Obligation ("ARO")

In March 2003, the CICA introduced new recommendations for the recognition, measurement and disclosure of liabilities for asset retirement obligations and the associated asset retirement costs. Effective fiscal 2003 the Trust adopted this new standard which applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development or normal use of the assets and requires that a liability for an asset retirement obligation be recognized when incurred, recorded at fair value and classified as a long-term liability in the balance sheet. When the liability is initially recorded, the entity will capitalize the net present value of the cost with an increase in the carrying value of the related long-lived asset. The capitalized amount is depleted on a unit-of-production basis over the life of the reserves. The liability amount is increased each reporting period due to the passage of time and this accretion amount is charged to earnings in the period. Revisions to the estimated timing of cash flows or to the original estimated undiscounted cost would also result in an increase or decrease to the ARO. Actual costs incurred upon settlement of the ARO are charged against the ARO to the extent of the liability recorded. Any difference between the actual costs incurred upon settlement of the ARO and the recorded liability is recognized as a gain or loss in the Trust's earnings in the period in which the settlement occurs.

The Trust has made a provision for estimated future asset retirement obligations associated with PP&E. These

obligations were measured at fair value which were discounted using the Trust's credit adjusted risk-free interest rate. The periodic charge to the provision is included as a charge against earnings. Actual site retirement and abandonment costs are charged against this obligation.

(f) Revenue Recognition

Revenue associated with the sale of crude oil, natural gas and natural gas liquids is recognized when title passes to the purchaser, normally at the pipeline delivery point for natural gas, and at the wellhead for crude oil.

(g) Income Taxes

The Trust is a taxable entity under the Income Tax Act (Canada) and is taxable only on income that is not distributed or distributable to the unitholders. As the Trust distributes all of its taxable income to the unitholders and meets the requirement of the Income Tax Act (Canada) applicable to the Trust, no provision for income taxes has been made in the Trust.

(h) Financial Instruments

The Trust is exposed to market risks resulting from fluctuations in commodity prices in the normal course of operations. The Trust uses various types of financial instruments to manage these market risks. Effective fiscal 2003, the Trust adopted the CICA's Accounting Guideline 13 on hedging relationships. Based on certain conditions established under the guideline, hedge accounting has been applied to options contracts held by the Trust at December 31, 2003. Had the Trust's contracts not qualified for hedge accounting, any changes in the mark-to-market value of the options contracts relating to a period would have either reduced or increased net income and net income per trust unit for that period.

Proceeds and costs realized from holding the crude oil and natural gas contracts are recognized as a component of the related transaction.

(i) Unit-Based Compensation Plan

The Trust has a unit-based compensation plan for employees and independent directors of the Trust. Compensation cost is measured based on the intrinsic value of the award at the date of grant and is recognized over the vesting period. Any consideration received by the Trust on exercise of the unit rights is credited to unitholders' capital. Units will be purchased from the market and not issued from treasury.

(j) Distributable Cash of the Trust

The amount of Distributable Cash of the Trust to be distributed monthly to unitholders is, as defined in the Trust Indenture, based generally on the amount by which the Trust's cash on hand exceeds: (i) all current liabilities and accrued liabilities including any interest and principal repayments on any indebtedness of the Trust; (ii) the aggregate value of all trust units redeemed during the month; and (iii) any cash reserve which management in its discretion determines is necessary to satisfy the Trust's current and anticipated obligations.

Distributable Cash, as defined above, is not a measure under GAAP and there is no standardized measure of Distributable Cash. Distributable Cash, as presented, may not be comparable to similar measures presented by other trusts.

(k) Net Earnings and Distributable Cash per trust unit

Basic and fully diluted net earnings and Distributable Cash per trust unit are calculated by dividing net earnings and Distributable Cash respectively, by the weighted average number of trust units outstanding during the period. For the purposes of the weighted average number of trust units calculation, trust units are determined to be outstanding from the date they are issued.

(l) Disclosure of Guarantees

Effective fiscal 2003, the Trust adopted the CICA's accounting guideline on disclosure of guarantees. In accordance with this guideline, all guarantees issued to third parties are disclosed.

3. BUSINESS ACQUISITION

On October 15, 2003, the Trust issued 18,454,200 trust units in an initial public offering (the "IPO") at a price of $10.00 per unit, for net proceeds of $173.1 million after transaction fees of $11.4 million. On the same date, the Trust issued 6,151,400 trust units at a price of $10.00 per unit to an indirect, wholly-owned subsidiary of Calpine Corporation for proceeds of $61.5 million ("Calpine Units").

The cash proceeds of $234.6 million along with $40.0 million of bank debt were used to acquire properties pursuant to a purchase and sale agreement effective October 15, 2003 (the "Initial Properties"). The acquisition has been accounted for using the purchase method of accounting as follows:

	2003
Consideration:	
Issuance of 24,605,600 trust units	$ 234,645
Bank debt	40,000
	$ 274,645
Right of first refusal ("ROFR") adjustment (1)	(405)
Seismic purchase adjustment (2)	(751)
	$ 273,489
Net assets acquired:	
Property, plant & equipment acquired (net) (1)	269,951
Forward sales contract	2,288
Seismic (2)	1,250
	$ 273,489

(1) Assets acquired pursuant to the purchase and sale agreement were subject to terms and conditions customary to transactions of this nature, including certain Initial Properties subject to ROFRs. Properties retained by external parties pursuant to ROFR offers totaled $405,340.

(2) Seismic originally valued at $2.0 million in the purchase and sale agreement was subsequently purchased by the Trust from an external vendor for $1.25 million, due to licensing requirements.

4. FORWARD SALES CONTRACT

Pursuant to the purchase and sale of Initial Properties, the Trust acquired a forward sales contract valued at $2.3 million (see Note 12 – Related Party Transactions, Energy Management Services Agreement). This asset has been capitalized and amortized over the term of the contract. The amortization for the period ended December 31, 2003 was $970,000. Under CICA recommendations, the contract has been accounted for under hedge accounting. The contract provides the Trust with a minimum price of $7.35/mcf on all production from the Initial Properties from October 15, 2003 to April 15, 2004.

5. RECLAMATION FUND

October 15 to December 31		2003
Balance, beginning of period	$	–
Contributions, net of expenditures		120
Interest earned on fund		–
Balance, end of period	$	120

A reclamation fund was established to reserve for future ARO expenditures (see Note 8). Fund contributions were approximately $0.28 per boe for the period ended December 31, 2003. Actual retirement obligation work undertaken in 2003 was funded from current period cash flow, and was not deducted from the fund balance. Contributions to the reclamation fund have been deducted from the calculation of Distributable Cash (see Note 11).

6. PROPERTY, PLANT AND EQUIPMENT

October 15 to December 31		2003
Property, plant and equipment	$	283,070
Accumulated depletion and depreciation		(7,920)
Property, plant and equipment, net	$	275,150

The calculation of 2003 depletion and depreciation included an estimated $14.4 million for future development costs associated with proved undeveloped reserves and excluded $2.8 million for the estimated future net realizable value of production equipment and facilities and $3.7 million for the estimated value of unproved properties. Depletion and depreciation expense for the period ended December 31, 2003 was $7.9 million.

Included in the Trust's PP&E balance is $4.5 million, net of accumulated depletion, relating to the ARO.

The Trust capitalized $84,000 of certain general and administrative expenses associated with the acquisition, exploration and development of capital assets during 2003.

The Trust performed a ceiling test calculation at December 31, 2003 to assess the recoverable value of PP&E. The ceiling test limits were calculated based on year end proved reserves and the Trust's expected future pricing obtained from third parties and adjusted for commodity differentials specific to the Trust. Future prices were obtained for the period 2004 to 2008 inclusive and then escalated based on escalation factors used in the Trust's year end independent reserves evaluation. Based on these assumptions, the carrying value of PP&E exceeded the sum of undiscounted cash flows expected by approximately $54.3 million.

The carrying value of PP&E was established through the IPO which was completed 78 days prior to year end. There was no significant change in the value of proved plus probable reserves from inception of the Trust to December 31, 2003 as calculated under National Instrument 51-101 and reviewed by an independent reserve engineer. As a consequence, the estimated fair value of the PP&E is not less than the carrying value and no impairment provision has been made.

The following table describes prices used for purposes of the impairment test (1):

	Crude Oil		Natural Gas	Natural Gas Liquids
Year	WTI ($US/bbl)	Edmonton Par Price ($Cdn/bbl)	AECO Gas Price ($Cdn/MMBTU)	($Cdn/bbl)
2004	29.00	37.75	5.85	31.25
2005	26.00	33.75	5.15	26.58
2006	25.00	32.50	5.00	25.33
2007	25.00	32.50	5.00	25.33
2008	25.00	32.50	5.00	25.33
2009 – 2014	25.00	32.50	5.00	25.33
Remainder (2)	1.5%	1.5%	1.5%	1.5%

Notes:

(1) GLJ's January 1, 2004 forecasted prices; future prices incorporated a $0.75 US/Cdn exchange rate.

(2) Percentage change of 1.5% represents the change in future prices in each year after 2014 to the end of the reserve life.

7. BANK DEBT

The Trust had two credit facilities (the "Facilities") under which it could borrow up to $71.0 million at December 31, 2003. These facilities were comprised of a syndicated revolving credit facility with a borrowing limit of $66.0 million (the "Revolving Facility") and a $5.0 million Working Capital Facility.

The Revolving Facility has a 364 day extendable revolving period expiring October 13, 2004. An additional 364 day period may be requested annually. If the revolving period is not extended, then the Revolving Facility will terminate on the last day of the revolving period and all outstanding amounts must be repaid in full on such date. The Working Capital Facility is demand in nature and will terminate upon the earlier of demand or termination of the Revolving Facility. Borrowings under the Facilities bear interest based on floating interest rates. Collateral for the Facilities is in the form of floating charges on all assets and undertakings of the Trust and its subsidiaries.

8. ASSET RETIREMENT OBLIGATION

The Trust adopted the CICA's new recommendation on asset retirement obligations at inception of the Trust. At October 15, 2003, the Trust identified obligations related to oil and gas properties and recorded a liability equal to the present value of expected future asset retirement obligations. The total future ARO was estimated by management based on the Trust's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon the wells and facilities and the estimated timing of the costs to be incurred in future periods. The Trust estimated the net present value of its total ARO to be $4.7 million as a December 31, 2003 based on a total future liability of $13.2 million and incorporated the Trust's estimated credit-adjusted risk-free interest rate of 8.5%. These payments are expected to be made over the next 27 years. A reclamation fund was established to fund future retirement obligations (see Note 5).

The following table reconciles the Trust's asset retirement obligations:

October 15 to December 31		2003
Asset retirement obligation, beginning of period	$	–
New liabilities incurred on purchase of Initial Properties		4,577
Liabilities settled		(6)
Accretion expense		83
Asset retirement obligation, end of period	$	4,654

9. FINANCIAL INSTRUMENTS

Financial instruments of the Trust carried on the balance sheet consist mainly of accounts receivable, operating advances, reclamation fund investments, accounts payable, distributions payable, commodity contracts and bank debt. Except as noted below, as at December 31, 2003, there were no significant differences between the carrying value of these financial instruments and their estimated fair value because of their short-term nature.

Substantially all of the Trust's accounts receivable are due from a related party under a Call on Production Agreement. Collateral has been received in support of this receivable as disclosed in Note 12 – Related Party Transactions, Call on Production Agreement.

The Trust is exposed to market risks resulting from fluctuations in commodity prices, foreign exchanges rates and interest rates in the normal course of operations. A variety of financial instruments are used by the Trust to manage these market risks. The fair value of these instruments are based on an approximation of the amounts that would have been paid to or received from counterparties to settle the instruments outstanding as at December 31, 2003 with reference to forward prices and mark-to-market valuations using independent sources. The Trust may be exposed to losses in the event of default by the counterparties to these instruments. This credit risk is controlled by the Trust through the selection of financially sound counterparties or through receipt of collateral in support of payment.

The Trust had the following financial contracts in place on its gross natural gas production as described below. The mark-to-market value of the financial contracts outstanding as at December 31, 2003 reflects an unrealized cost of $231,666.

The following table summarizes the Trust's risk management positions as at December 31, 2003:

Commodity	Daily Notional Contract Quantity	Contract Price	Price Index	Term
Natural Gas Forward Sales Contract	100% of production on Initial Properties	min $7.35/mcf	AECO	October 15, 2003 to April 15, 2004
Natural Gas Fixed Price Contract	6,200 GJ	$5.20/GJ	AECO	April 1, 2004 to October 31, 2004
Natural Gas Collared Contract	6,200 GJ	min $4.75/GJ max $5.85/GJ	AECO	April 1, 2004 to October 31, 2004
Natural Gas Collared Contract	6,100 GJ	min $5.00/GJ max $6.80/GJ	AECO	November 1, 2004 to March 31, 2005

10. UNITHOLDERS' EQUITY

The Trust Indenture provides that an unlimited number of trust units may be authorized and issued. Each trust unit is transferable, carries the right to one vote and represents an equal undivided beneficial interest in any distributions from the Trust and in the net assets of the Trust in the event of termination or winding-up of the Trust. All trust units are of the same class with equal rights and privileges.

The trust units are redeemable at the holder's option at an amount equal to the lesser of: (a) 90% of the weighted average price per trust unit during the period of the last 10 days during which the trust units were traded on the Toronto Stock Exchange; and (b) the closing market price at the date of redemption as defined in the Trust Indenture. Redemptions are subject to a maximum of $250,000 in cash redemptions in any particular month. Redemptions in excess of this amount will be paid by way of a distribution of notes issued by the Commercial Trust to the Trust.

TRUST UNITS ISSUED AND UNITHOLDERS' CAPITAL

October 15 to December 31	Number of trust units	2003
Initial Public Offering, net of transaction fees (Note 3)	18,454,200	$ 173,131
Calpine Units (Note 3)	6,151,400	61,514
Over-allotment exercise, net of transaction fees [(1)]	2,460,560	23,544
As at December 31, 2003	27,066,160	$ 258,189

(1) On October 22, 2003, the over-allotment option that was granted as part of the IPO of trust units was fully exercised. As a result, an additional 1,845,420 trust units were issued at a price of $10.00 per unit, for net proceeds of $17.4 million. Concurrently, 615,140 trust units were issued to an indirect, wholly-owned subsidiary of Calpine Corporation at $10.00 per trust unit for additional net proceeds of $6.2 million. Total net proceeds of $23.6 million from the exercise of the over-allotment option was used to reduce bank debt from approximately $40.0 million to $16.4 million.

The quoted market value of the Trust's unitholder equity at December 31, 2003, as indicated by the closing price per trust unit on the Toronto Stock Exchange was $330.2 million.

11. UNITHOLDER DISTRIBUTIONS

October 15 to December 31	2003
Funds from operations	$ 9,930
Contributions to reclamation fund	(120)
Distribution adjustment	340
Distributable cash	10,150
Number of trust units outstanding	27,066,160
Distributable cash per trust unit	$ 0.3750

The Trust is required under the Trust Indenture to pay monthly distributions to unitholders from its cash flow from operations after deducting certain items. Distributions are declared to unitholders of record on the last day of the month and paid on the 15th day of the following month.

12. RELATED PARTY TRANSACTIONS

Calpine Energy Holdings Limited, an indirect wholly-owned Canadian subsidiary of Calpine Corporation ("Calpine"), acquired 6,151,400 trust units of the Trust concurrent with closing of the IPO, and 615,140 trust units of the Trust concurrent with the additional issue of trust units to the underwriters of the IPO pursuant to an over-allotment option, for total consideration of $67.7 million. At December 31, 2003, 25% of the total trust units outstanding were owned by this Canadian affiliate of Calpine.

In conjunction with the closing of the IPO, the Trust acquired properties from Calpine Canada Natural Gas Partnership ("CCNGP"), an indirect wholly-owned subsidiary of Calpine for $272.2 million pursuant to a Purchase and Sale Agreement effective October 15, 2003 (see Note 3). This transaction was recorded based on the fair market value of properties acquired.

Concurrent with the completion of the closing of the IPO, the following agreements were entered into between the Trust and certain indirect wholly-owned Canadian subsidiaries of Calpine:

Call on Production Agreement

Under a Call on Production Agreement, CCNGP has the right to purchase up to 100% of the production of natural gas and petroleum from the properties (including both the Initial Properties and subsequently acquired properties – see Note 14). The price that CCNGP pays for natural gas is the daily spot price established by published indices (daily spot gas price at AECO), and the price that CCNGP pays for crude oil and natural gas liquids is its realized price negotiated with third party buyers. The Call on Production Agreement has a twenty year term, plus two automatic five year renewal terms, unless either party provides notice that it does not agree to renew the agreement. The Call on Production Agreement requires CCNGP to provide credit support in an amount sufficient to cover its payment obligations to the Trust. Initially, the credit support consists of a pledge by Calpine Corporation of its trust units (market value at December 31, 2003 was $82.6 million) that it owns or controls along with the associated cash distributions.

Energy Management Services Agreement

CCNGP arranges all marketing and transportation services for the Trust's natural gas and petroleum production pursuant to an Energy Management Services Agreement. CCNGP provides these services on an expense reimbursement basis pursuant to a Services Agreement. In addition, a financial contract between CCNGP and the Trust was put in place concurrent with the completion of the IPO (see Note 4). Proceeds and costs realized from this contract are recognized in oil and natural gas revenues as a component of the related transaction. Under the contract, the Trust has recognized $2.3 million in revenue from October 15, 2003 to December 31, 2003.

Governance Agreement

A Governance Agreement provides that there will be a minimum of seven and a maximum of eleven directors. Of the total directors, should Calpine beneficially own, directly or indirectly, no less than 15% of the trust units outstanding, Calpine will be entitled to elect three directors and appoint the Chairman of the Board of Directors. The current Board consists of seven directors; four directors are independent of Calpine (the "Independent Directors"), with the remaining three, including the Chairman, elected by Calpine. Ownership of less than 15% but at least 8% of the issued and outstanding trust units will entitle Calpine to appoint two directors, including the Chairman, and ownership of less than 8% but at least 1% of the issued and outstanding trust units will entitle Calpine to appoint one director, but Calpine will not be entitled to appoint the Chairman.

Participation Agreement

Pursuant to a Participation Agreement, the Trust has the right to participate in certain acquisitions of developed natural gas and oil properties by direct and indirect wholly-owned Canadian subsidiaries of Calpine located in Alberta, British Columbia and Saskatchewan. The Trust can elect to participate in up to 50% of certain interests acquired by Calpine in the developed properties. In addition, if Calpine wishes to sell any natural gas or petroleum properties, the Participation Agreement provides that, prior to Calpine commencing any marketing or sale process, the Trust will have the exclusive right to review the subject properties for a specified period and, prior to the expiration of such period, offer to purchase those properties.

The Participation Agreement has a twenty year term, plus two automatic five year renewal terms, unless either party provides notice that it does not agree to renew the agreement. The Participation Agreement will also terminate upon Calpine and its affiliates collectively owning less than 8% of the issued and outstanding trust units. In addition, either the Partnership or CCNGP may terminate the agreement if Calpine is acquired pursuant to a take-over bid or similar transaction.

Pre-Emptive Rights Agreement

A Pre-Emptive Rights Agreement provides that Calpine, at the time in which the Trust issues additional trust units, will have the right to maintain its pro rata share of the then outstanding trust units (so long as Calpine's ownership position in the Trust is not less than 1% of the outstanding trust units). Through the agreement, Calpine is entitled to purchase such number of additional trust units at the same price of which the securities are issued to the public.

This pre-emptive right can be exercised by either private placement (including in connection with an acquisition) or in connection with a public offering, and consideration can be in the form of cash, or where mutually agreed upon by the Independent Directors and Calpine, natural gas and petroleum properties of Calpine.

Services Agreement

Calpine Natural Gas Services Limited ("Calpine Services"), an indirect wholly-owned Canadian subsidiary of Calpine, provides administrative and operating services to the Trust pursuant to a Services Agreement entered into between subsidiaries of the Trust and Calpine Services. The Services Agreement has an initial ten year term which expires October 15, 2013 and will be renewed for one additional term of five years, unless terminated by the Trust. Under the Services Agreement, Calpine Services provides certain administrative and operating services in order to assist management of the Trust in performing their duties and obligations. Services are provided at the request of, and subject to, the overall supervision and direction of the directors and the independent executive officers of the Trust. Calpine Services provides services on an expense reimbursement basis.Total costs for these services for the period ended December 31, 2003 was $380,000.

As at December 31, 2003, the Trust had the following balances receivable from (payable to) related parties in the normal course of business:

Distributions payable to Calpine	$ (1,015)
Accounts payable to Calpine under a Services Agreement	(404)
Accrued accounts receivable under a Call on Production and Energy Management Services Agreement	6,612

13. COMMITMENTS

At December 31, 2003, the Trust had standby letters of credit with various counterparties totaling $1.4 million.

14. SUBSEQUENT EVENTS

The Trust entered into an acquisition agreement pursuant to which it acquired, from a wholly-owned subsidiary of Calpine, natural gas producing properties for approximately $40.5 million. The transaction was effective January 1, 2004 and closed on February 18, 2004. The acquisition was financed through the Trust's existing bank facility. The properties include a mix of operated and non-operated interests with the most significant interest in the Peace River Arch area of northwestern Alberta.

In conjunction with the property purchase, the Trust's lenders increased the Trust's two credit facilities under which it could borrow up to $82.0 million. The syndicated revolving credit facility was increased from a borrowing limit of $66.0 million to $72.0 million and the Working Capital Facility increased from $5.0 million to $10.0 million.

As part of the property purchase, the Trust entered into a natural gas fixed price contract for $5.90 per gigajoule for the period April 1, 2004 to October 31, 2004 for 4,500 gigajoules per day and a natural gas collared contract for a minimum $5.25 per gigajoule and a maximum $8.15 per gigajoule for the period November 1, 2004 to March 31, 2005 for 2,000 gigajoules per day. Both contracts are at AECO and are with third party counterparties.

CORPORATE GOVERNANCE

The Directors and management team are committed to best practices of corporate governance. Effective governance requires specified reporting structures and business processes, a strategic plan and the commitment to adhere to these structures, processes and plans. The Directors believe that not only does sound corporate governance improve confidence and enhance trust in Calpine Natural Gas Trust, it also contributes to long-term unitholder value.

The Toronto Stock Exchange has set out guidelines for effective corporate governance for boards of TSX-listed enterprises. The guidelines constitute a voluntary code of structure and procedure, and listed enterprises must disclose annually their approach to corporate governance with specific reference to these guidelines. The Directors believe that the Trust meets these guidelines and has disclosed its Statement of Corporate Governance Practices, in its 2004 Management Proxy Circular for the Annual General Meeting.

The Calpine Natural Gas Trust conforms in all material respects to the TSX guidelines to the extent consistent with the structure of the Trust. In addition, the Trust Indenture mandates that the Trust Directors act honestly and in good faith with a view to the best interest of the Trust.

A majority of the Directors (four of seven) are independent and unrelated to CNG Trust as defined in the TSX Guidelines. Further, the Audit Committee and the Corporate Governance Committee are each comprised of Independent Directors.

The Corporate Governance Committee is responsible for assessing corporate governance guidelines, evaluating the effectiveness of the Directors, evaluating the Directors' and Management's Compensation, reviewing the performance of management and reviewing and recommending independent candidates to act as Directors.

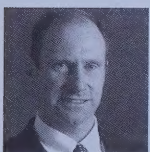
The Directors have adopted a public disclosure policy to ensure the Trust provides timely, complete, consistent, fair and credible public disclosure of material information. The Directors have also adopted an insider trading policy to govern trading in units of the Trust by insiders and their affiliates. Finally, the Directors have formulated a formal code of business conduct regarding the duties of Directors and employees working on behalf of the Trust.

The Directors bring valuable knowledge to the Trust in the areas of Energy, Financial Reporting, Capital Markets, Acquisitions and Engineering. Four of the seven Directors are independent from management.

DIRECTORS

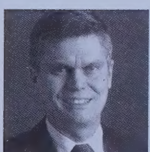
Bill A. Berilgen
Chairman and Director

Bill A. Berilgen. Mr. Berilgen is currently the Executive Vice President of Calpine and President of Calpine Natural Gas Company. He initially joined Calpine in 1999 as a Senior Vice President and has over thirty-three years experience in the oil and gas business. Prior to joining Calpine, Mr. Berilgen worked at Forest Oil from 1984 until mid-1997 in a variety of management and executive positions, including his appointment as Vice President and Chief Technical Officer in 1996. In June 1997, Mr. Berilgen joined Sheridan Energy, a public oil and gas company, as its President and Chief Executive Officer, until it was acquired by Calpine in 1999. Mr. Berilgen attended the University of Oklahoma, receiving a Bachelor of Science in Petroleum Engineering in 1970. Additionally, he has a Masters of Science in Industrial Engineering/Management Science from the University of Oklahoma.



Toby Austin
Director and Corporate Secretary

Toby Austin. Mr. Austin is currently the Vice President, Managing Counsel of Calpine Canada, a Trustee of the Calpine Power Income Fund (a TSX-listed income fund) and President and Chief Executive Officer of Calpine Canada Power Ltd., the manager of the Calpine Power Income Fund. Mr. Austin joined Calpine Canada in April 2001. Prior to joining Calpine, Mr. Austin was General Manager, Western Canada, IPP Division for TransAlta Corporation from 2000 to 2001. From 1995 to 2000 he was General Counsel of TransAlta's IPP group. Mr. Austin has worked for Syncrude Canada at its Fort McMurray operations and spent three years in London with Standard Chartered Bank. Mr. Austin holds degrees from the University of Cambridge (LL.M) and University of Calgary (LL.B).



Wayne Foo
Director and Chairman of the Reserves Committee

Wayne Foo. Mr. Foo currently provides consulting and investment services to Hardisty Resources Ltd., a private oil and gas company and provides stewardship and First Nations policy work for the Canadian Association of Petroleum Producers ("CAPP") and the province of British Columbia regarding the establishment of junior exploration and production companies in western Canada and South America. From April 1998 to October 2002, Mr. Foo was President and Chief Executive Officer of Dominion Energy Canada Ltd. and Senior Vice President of its parent, Dominion Resources Inc., a public U.S. oil and gas company, following its acquisition of Archer Resources Ltd., a former TSX-listed oil and gas company, where he was Vice President, Exploration and subsequently President and Chief Operating Officer from October 1996 to April 1998. From 1983 to July 1994, he held several positions in the Chevron organization in both Canada and the United States, dealing with both domestic and international exploration and production matters. Mr. Foo received a Bachelor of Science (with First Class Honours) in Geology from the University of Calgary in 1977 and a Masters of Science in Geology from Queen's University in 1979, and is a Professional Geologist. Mr. Foo was a member of the Board of Governors of CAPP from 2001 to 2003, chaired CAPP's Fiscal Executive Policy Group and the British Columbia Executive Policy Group and served on the Climate Change CEO Task Force.

John King
Director

John King. Mr. King is currently the Senior Vice President, International Operations and Corporate Planning of Calpine. In addition, Mr. King is a Trustee on the Calpine Power Income Fund, a TSX listed trust. Mr. King joined the Calpine finance department in 1995, and currently is responsible for international operations and corporate financial planning. From 1997 until 2000, Mr. King was a Vice President of Business Development, responsible for numerous acquisitions, including Gas Energy Inc., Cogeneration Company of America and Sheridan Energy Inc. (now Calpine Natural Gas). In 2000 and 2001, Mr. King was in charge of business development in the western United States. Prior to joining Calpine, Mr. King was the Chief Operating Officer of Charter Media, Inc. He holds a Bachelor of Science and a Bachelor of Commerce degree from Santa Clara University, and an MBA from California State University, Hayward.

Robert B. Michaleski
Director and Chairman of the Governance Committee

Robert B. Michaleski. Mr. Michaleski has been the President and Chief Executive Officer of Pembina Pipeline Corporation ("Pembina"), the primary operating subsidiary of TSX-listed Pembina Pipeline Income Fund, since January 2000. Mr. Michaleski's lengthy association with Pembina began in September 1978 when he joined the Loram Group as Manager of Internal Audit. Following that, he was appointed as Controller of Pembina in January 1980 and Vice President Finance in September 1992. In connection with Pembina Pipeline Income Fund's initial public offering in October 1997, he was named Vice President Finance and Chief Financial Officer of Pembina. Mr. Michaleski is currently a director of Pembina, Real Resources Inc., a TSX-listed oil and gas company, and two private companies, Coril Holdings Ltd. and Coril Trust Company. Mr. Michaleski graduated from the University of Manitoba in 1975 with a Bachelor of Commerce (Honours) and received his Chartered Accountant designation in 1978.

Doug Palmer
Director

Doug Palmer. Mr. Palmer is currently an independent businessman involved in the oil and natural gas industry. From 1998 to 2001, he was President and Chief Executive Officer of Numac Energy Inc., a former TSX-listed oil and gas company, which was sold to Anderson Exploration Company in 2001. Prior to that, Mr. Palmer held various positions with Norcen Energy Resources Limited ("Norcen"), a public oil and gas company, and its affiliates from 1978 through 1998, including various Vice President capacities from 1989 to 1994 in both Calgary and Houston. From 1994 to 1998 he was Senior Vice President and Chief Operating Officer of Norcen's worldwide operations until it was sold to Union Pacific Resources Inc. in 1998. Mr. Palmer earned a Bachelor of Science in Chemical Engineering (with Distinction) from the University of Calgary in 1978.

W. Mark Schweitzer
Director and Chairman of the Audit Committee

W. Mark Schweitzer. Mr. Schweitzer is currently the Executive Vice President, Corporate Development and Chief Financial Officer of Superior Plus Inc., a wholly-owned subsidiary of TSX-listed Superior Plus Income Fund. Through its divisions, Superior Plus Inc. is Canada's largest distributor of propane and related products and services, a leading North American supplier of chemicals and related technology to the pulp and paper and water treatment industries and a provider of natural gas marketing supply services predominantly to commercial and industrial markets in Ontario. From 1994 to 1998, Mr. Schweitzer was the Vice President, Finance and Chief Financial Officer of Norcen Energy Resources Limited, a public oil and gas company. Prior thereto, in 1994, Mr. Schweitzer was the Controller and Treasurer of Canadian Hunter Exploration Ltd. and prior to that appointment, Mr. Schweitzer held various management positions with Noranda Inc. from 1988 to 1994. Mr. Schweitzer graduated from Queen's University in 1983 with a Bachelor of Commerce (Honours) and received his Chartered Accountant designation in 1985.

CORPORATE INFORMATION

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Calpine Natural Gas Limited

Mark Kuhn
Vice President
Business Development
Calpine Natural Gas Limited

Art MacNichol
Vice President, Finance &
Chief Financial Officer
Calpine Natural Gas Limited

TRUSTEE AND TRANSFER AGENT
Computershare Trust Company of Canada
Calgary, Alberta

AUDITORS
PricewaterhouseCoopers LLP.
Calgary, Alberta

LEGAL COUNSEL
Blake Cassels & Graydon LLP

ENGINEERING CONSULTANTS
Gilbert Laustsen Jung Associated Ltd.
Calgary, Alberta

STOCK EXCHANGE
The Toronto Stock Exchange Trading Symbol
CXT.UN

ANNUAL GENERAL MEETING
Friday, May 7, 2004 at 3:00 pm
Calgary Petroleum Club
319 – 5th Avenue S.W.
Calgary, Alberta

BOARD OF DIRECTORS
Bill Berilgen (1)(4)
Executive Vice President
Calpine Corporation

Toby Austin
Vice President, Managing Counsel
Calpine Canada Energy Ltd.

Wayne Foo (3)(4)
Independent businessman and
Consultant to Hardisty Resources

John King
Senior Vice President
International Operations and
Planning of Calpine Corporation

Robert B. Michaleski (2)(3)
President and Chief Executive Officer
Pembina Pipeline Corporation

Doug Palmer (2)(4)
Independent businessman

Mark Schweitzer (2)(3)
Executive Vice President,
Corporate Development
Chief Financial Officer
Superior Plus Inc.

(1) Chairman of the Board
(2) Member of the Corporate Governance Committee
(3) Member of the Audit Committee
(4) Member of the Reserves Committee

INVESTOR RELATIONS
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